Control Number: 51415

Item Number: 1

Addendum StartPage: 0

generating units include: (a) periodic revisions to NAAQS and the development of SIPs to achieve any more stringent standards, (b) implementation of the regional haze program by the states and the Federal EPA, (c) regulation of hazardous air pollutant emissions under MATS, (d) implementation and review of CSAPR and (e) the Federal EPA's regulation of greenhouse gas emissions from fossil generation under Section 111 of the CAA. Notable developments in significant CAA regulatory requirements affecting AEP's operations are discussed in the following sections.

National Ambient Air Quality Standards

The Federal EPA issued new, more stringent NAAQS for PM in 2012 and ozone in 2015. The Federal EPA is currently reviewing both of these standards. The existing standards for NO_2 and SO_2 were retained after review by the Federal EPA in 2018 and 2019, respectively. Implementation of these standards is underway.

The Federal EPA finalized non-attainment designations for the 2015 ozone standard in 2018. The Federal EPA confirmed that for states included in the CSAPR program, there are no additional interstate transport obligations, as all areas of the country are expected to attain the 2008 ozone standard before 2023. Challenges to the 2015 ozone standard and the Federal EPA's determination that CSAPR satisfies certain states' interstate transport obligations were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In August 2019, the court upheld the 2015 primary ozone standard, but remanded the secondary welfare-based standard for further review. The court vacated the Federal EPA's determination that CSAPR fulfilled the states' interstate transport obligations, because the Federal EPA's modeling analysis did not demonstrate that all significant contributions would be eliminated by the attainment deadlines for downwind states. Any further changes will require additional rulemaking. Management cannot currently predict the nature, stringency or timing of additional requirements for AEP's facilities based on the outcome of these activities.

Regional Haze

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) would address regional haze in federal parks and other protected areas. BART requirements apply to power plants. CAVR will be implemented through SIPs or FIPs. In 2017, the Federal EPA revised the rules governing submission of SIPs to implement the visibility programs, including a provision that postpones the due date for the next comprehensive SIP revisions until 2021. Petitions for review of the final rule revisions have been filed in the U.S. Court of Appeals for the District of Columbia Circuit.

The Federal EPA initially disapproved portions of the Arkansas regional haze SIP, but has approved a revised SIP and all of SWEPCo's affected units are in compliance with the relevant requirements.

The Federal EPA also disapproved portions of the Texas regional haze SIP. In 2017, the Federal EPA finalized a FIP that allows participation in the CSAPR ozone season program to satisfy the NO_x regional haze obligations for electric generating units in Texas. Additionally, the Federal EPA finalized an intrastate SO_2 emissions trading program based on CSAPR allowance allocations. A challenge to the FIP was filed in the U.S. Court of Appeals for the Fifth Circuit and the case is pending the Federal EPA's reconsideration of the final rule. In August 2018, the Federal EPA proposed to affirm its 2017 FIP approval. In November 2019, in response to comment, the Federal EPA proposed revisions to the intrastate trading program. Management supports the intrastate trading program as a compliance alternative to source-specific controls.

Cross-State Air Pollution Rule

In 2011, the Federal EPA issued CSAPR as a replacement for the Clean Air Interstate Rule, a regional trading program designed to address interstate transport of emissions that contributed significantly to downwind non-attainment with the 1997 ozone and PM NAAQS. CSAPR relies on SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units. Interstate trading of allowances is allowed on a restricted sub-regional basis.

Petitions to review the CSAPR were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2015, the court found that the Federal EPA over-controlled the SO_2 and/or NO_x budgets of 14 states. The court remanded the rule to the Federal EPA for revision consistent with the court's opinion while CSAPR remained in place.

In 2016, the Federal EPA issued a final rule, the CSAPR Update, to address the remand and to incorporate additional changes necessary to address the 2008 ozone standard. The CSAPR Update significantly reduced ozone season budgets in many states and discounted the value of banked CSAPR ozone season allowances beginning with the 2017 ozone season. In 2019, the appeals court remanded the CSAPR Update to the Federal EPA because it determined the Federal EPA had not properly considered the attainment dates for downwind areas in establishing its partial remedy, and should have considered whether there were available measures to control emissions from sources other than generating units. Any further changes to the CSAPR rule will require additional rulemaking.

Mercury and Other Hazardous Air Pollutants (HAPs) Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule established unit-specific emission rates for units burning coal on a 30-day rolling average basis for mercury, PM (as a surrogate for particles of non-mercury metals) and hydrogen chloride (as a surrogate for acid gases). In addition, the rule proposed work practice standards for controlling emissions of organic HAPs and dioxin/furans, with compliance required within three years. Management obtained administrative extensions for up to one year at several units to facilitate the installation of controls or to avoid a serious reliability problem.

In 2014, the U.S. Court of Appeals for the District of Columbia Circuit denied all of the petitions for review of the 2012 final rule. Various intervenors filed petitions for further review in the U.S. Supreme Court.

In 2015, the U.S. Supreme Court reversed the decision of the U.S. Court of Appeals for the District of Columbia Circuit. The court remanded the MATS rule to the Federal EPA to consider costs in determining whether to regulate emissions of HAPs from power plants. In 2016, the Federal EPA issued a supplemental finding concluding that, after considering the costs of compliance, it was appropriate and necessary to regulate HAP emissions from coal and oil-fired units. Petitions for review of the Federal EPA's determination were filed in the U.S. Court of Appeals for the District of Columbia Circuit. In 2018, the Federal EPA released a revised finding that the costs of reducing HAP emissions to the level in the current rule exceed the benefits of those HAP emission reductions. The Federal EPA also determined that there are no significant changes in control technologies and the remaining risks associated with HAP emissions do not justify any more stringent standards. Therefore, the Federal EPA proposed to retain the current MATS standards without change.

Climate Change, CO_2 Regulation and Energy Policy

In 2015, the Federal EPA published the final CO_2 emissions standards for new, modified and reconstructed fossil generating units, and final guidelines for the development of state plans to regulate CO_2 emissions from existing sources, known as the Clean Power Plan (CPP).

In 2016, the U.S. Supreme Court issued a stay of the final CPP, including all of the deadlines for submission of initial or final state plans until a final decision is issued by the U.S. Court of Appeals for the District of Columbia Circuit and the U.S. Supreme Court considers any petition for review. In 2017, the President issued an Executive Order directing the Federal EPA to reconsider the CPP and the associated standards for new sources. The Federal EPA filed a motion to hold the challenges to the CPP in abeyance pending reconsideration. In September 2019, following the Federal EPA's repeal of the CPP and promulgation of a replacement rule, the Court of Appeals for the District of Columbia Circuit dismissed the challenges.

In July 2019, the Federal EPA finalized the Affordable Clean Energy (ACE) rule to replace the CPP with new emission guidelines for regulating CO_2 from existing sources. ACE establishes a framework for states to adopt standards of performance for utility boilers based on heat rate improvements for such boilers. The final rule applies to generating units that commenced construction prior to January 2014, generate greater than 25 MWs, have a baseload rating above 250 MMBtu per hour and burn coal for more than 10% of the annual average heat input over the preceding three calendar years, with certain exceptions. States must establish standards of performance for each affected facility in terms of pounds of CO_2 emitted per MWh, based on certain heat rate improvement measures and the degree of emission reduction achievable through each applicable measure, together with consideration of certain site-specific factors and the unit's remaining useful life. State plans are required to be submitted in 2022, and the Federal EPA has up to two years to review and approve a plan or disapprove it and adopt a federal plan. The final ACE rule has been challenged in the courts.

In 2018, the Federal EPA filed a proposed rule revising the standards for new sources and determined that partial carbon capture and storage is not the best system of emission reduction because it is not available throughout the U.S. and is not cost-effective. Management continues to actively monitor these rulemaking activities.

AEP has taken action to reduce and offset CO_2 emissions from its generating fleet. AEP expects CO_2 emissions from its operations to continue to decline due to the retirement of some of its coal-fired generation units, and actions taken to diversify the generation fleet and increase energy efficiency where there is regulatory support for such activities. The majority of the states where AEP has generating facilities passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements that can assist in reducing carbon emissions. Management is taking steps to comply with these requirements, including increasing wind and solar installations, purchasing renewable power and broadening AEP System's portfolio of energy efficiency programs.

In September 2019, AEP announced new intermediate and long-term CO_2 emission reduction goals, based on the output of the company's integrated resource plans, which take into account economics, customer demand, grid reliability and resiliency, regulations and the company's current business strategy. The intermediate goal is a 70% reduction from 2000 CO_2 emission levels from AEP generating facilities by 2030; the long-term goal is to surpass an 80% reduction of CO_2 emissions from AEP generating facilities from 2000 levels by 2050. AEP's total estimated CO_2 emissions in 2019 were approximately 58 million metric tons, a 65% reduction from AEP's 2000 CO_2 emissions. AEP has made significant progress in reducing CO_2 emissions from its power generation fleet and expects its emissions to continue to decline. AEP's aspirational emissions goal is zero CO_2 emissions by 2050. Technological advances, including energy storage, will determine how quickly AEP can achieve zero emissions while continuing to provide reliable, affordable power for customers.

Federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs. which in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force AEP to close some coal-fired facilities, which could possibly lead to impairment of assets.

Coal Combustion Residual (CCR) Rule

In 2015, the Federal EPA published a final rule to regulate the disposal and beneficial re-use of CCR, including fly ash and bottom ash created from coal-fired generating units and FGD gypsum generated at some coal-fired plants. The rule applies to active CCR landfills and surface impoundments at operating electric utility or independent generation facilities. The rule imposes construction and operating obligations, including location restrictions, liner criteria, structural integrity requirements for impoundments, operating criteria and additional groundwater monitoring requirements to be implemented on a schedule spanning an approximate four-year implementation period. In 2018, some of AEP's facilities were required to begin monitoring programs to determine if unacceptable groundwater impacts will trigger future corrective measures. Based on additional groundwater data, further studies to design and assess appropriate corrective measures have been undertaken at four facilities.

In a challenge to the final 2015 rule, the parties initially agreed to settle some of the issues. In 2018, the U.S. Court of Appeals for the District of Columbia Circuit addressed or dismissed the remaining issues in its decision vacating and remanding certain provisions of the 2015 rule. The provisions addressed by the court's decision, including changes to the provisions for unlined impoundments and legacy sites, will be the subject of further rulemaking consistent with the court's decision.

Prior to the court's decision, the Federal EPA issued the July 2018 rule that modifies certain compliance deadlines and other requirements in the 2015 rule. In December 2018, challengers filed a motion for partial stay or vacatur of the July 2018 rule. On the same day, the Federal EPA filed a motion for partial remand of the July 2018 rule. The court granted the Federal EPA's motion. In November 2019, the Federal EPA proposed revisions to implement the court's decision regarding the timing for closure of unlined surface impoundments along with impoundments not meeting the required distance from an aquifer. The comment period closed in January 2020. In December 2019, the Federal EPA proposed a federal permit program, implementing the Water Infrastructure Improvements for the Nation Act, that would apply in states that do not have an approved CCR program.

Other utilities and industrial sources have been engaged in litigation with environmental advocacy groups who claim that releases of contaminants from wells, CCR units, pipelines and other facilities to groundwaters that have a hydrologic connection to a surface water body represent an "unpermitted discharge" under the CWA. Two cases were accepted by the U.S. Supreme Court for further review of the scope of CWA jurisdiction. The Federal EPA opened a rulemaking docket to solicit information to determine whether it should provide additional clarification of the scope of CWA permitting requirements for discharges to groundwater, and issued an interpretive statement finding that discharges to groundwater are not subject to NPDES permitting requirements under the CWA. Management is unable to predict the impact of this guidance or the outcome of these cases on AEP's facilities.

Because AEP currently uses surface impoundments and landfills to manage CCR materials at generating facilities, significant costs will be incurred to upgrade or close and replace these existing facilities and conduct any required remedial actions. Closure and post-closure costs have been included in ARO in accordance with the requirements in the final rule. Additional ARO revisions will occur on a site-by-site basis if groundwater monitoring activities conclude that corrective actions are required to mitigate groundwater impacts, which could include costs to remove ash from some unlined units. In January 2020, a bill was introduced in Virginia to require removal of ash from units at the retired Glen Lyn Station, and provide for recovery of the costs incurred to remove the ash and close those units. If removal of ash is required without providing similar assurances of cost recovery in regulated jurisdictions, it would impose significant additional operating costs on AEP, which could lead to increased financing costs and liquidity needs. Other units in Virginia, Ohio, West Virginia, and Kentucky already have been closed in place in accordance with state law programs. Management will continue to evaluate the rule's impact on operations.

Clean Water Act Regulations

In 2014, the Federal EPA issued a final rule setting forth standards for existing power plants that is intended to reduce mortality of aquatic organisms impinged or entrained in the cooling water. The rule was upheld on review by the U.S. Court of Appeals for the Second Circuit. Compliance timeframes are established by the permit agency through each facility's NPDES permit as those permits are renewed and have been incorporated into permits at several AEP facilities. Additional AEP facilities are reviewing these requirements as their wastewater discharge permits are renewed and making appropriate adjustments to their intake structures.

In 2015, the Federal EPA issued a final rule revising effluent limitation guidelines for generating facilities. The rule established limits on FGD wastewater, fly ash and bottom ash transport water and flue gas mercury control wastewater to be imposed as soon as possible after November 2018 and no later than December 2023. These requirements would be implemented through each facility's wastewater discharge permit. The rule was challenged in the U.S. Court of Appeals for the Fifth Circuit. In 2017, the Federal EPA announced its intent to reconsider and potentially revise the standards for FGD wastewater and bottom ash transport water. The Federal EPA postponed the compliance deadlines for those wastewater categories to be no earlier than 2020, to allow for reconsideration. In April 2019, the Fifth Circuit vacated the standards for landfill leachate and legacy wastewater, and remanded them to the Federal EPA for reconsideration. In November 2019, the Federal EPA proposed revisions to the guidelines for existing generation facilities. The comment period ended in January 2020. Management is assessing technology additions and retrofits to comply with the rule and the impacts of the Federal EPA's recent actions on facilities' wastewater discharge permitting.

In 2015, the Federal EPA and the U.S. Army Corps of Engineers jointly issued a final rule to clarify the scope of the regulatory definition of "waters of the United States" in light of recent U.S. Supreme Court cases. Various parties challenged the 2015 rule in different U.S. District Courts, which resulted in a patchwork of applicability of the 2015 rule and its predecessor. In December 2018, the Federal EPA and the U.S. Army Corps of Engineers proposed a replacement rule. In September 2019, the Federal EPA repealed the 2015 rule. A final rule was issued in January 2020, which limits that scope of CWA jurisdiction to four categories of waters, and clarifies exclusions for ground water, ephemeral streams, ditches, artificial ponds and waste treatment systems.

RESULTS OF OPERATIONS

SEGMENTS

AEP's primary business is the generation, transmission and distribution of electricity. Within its Vertically Integrated Utilities segment, AEP centrally dispatches generation assets and manages its overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

AEP's reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEP Texas and OPCo.
- OPCo purchases energy and capacity at auction to serve SSO customers and provides transmission and distribution services for all connected load.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in AEPTCo. These investments have FERC-approved returns on equity.
- Development, construction and operation of transmission facilities through investments in AEP's transmission-only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

Generation & Marketing

- Contracted renewable energy investments and management services.
- Competitive generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO.

The remainder of AEP's activities are presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes the purchasing of receivables from certain AEP utility subsidiaries, Parent's guarantee revenue received from affiliates, investment income, interest income, interest expense, income tax expense and other nonallocated costs.

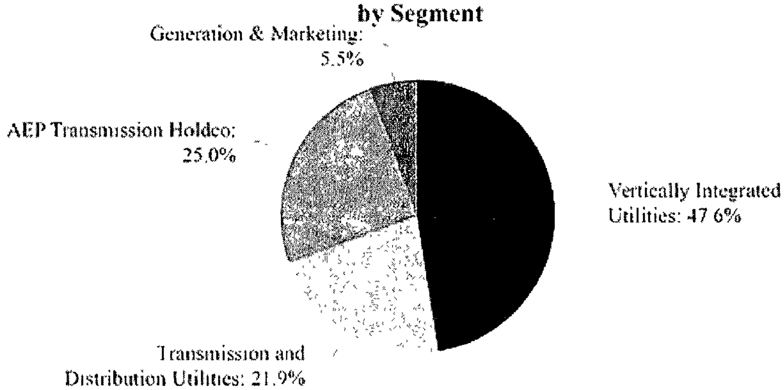
The following discussion of AEP's 2019 results of operations by operating segment includes an analysis of Gross Margin, which is a non-GAAP financial measure. Gross Margin includes Total Revenues less the costs of Fuel and Other Consumables Used for Electric Generation as well as Purchased Electricity for Resale, Generation Deferrals and Amortization of Generation Deferrals as presented in the Registrants' statements of income as applicable. Under the various state utility rate making processes, these expenses are generally reimbursable directly from and billed to customers. As a result, these expenses do not typically impact Operating Income or Earnings Attributable to AEP Common Shareholders. Management believes that Gross Margin provides a useful measure for investors and other financial statement users to analyze AEP's financial performance in that it excludes the effect on Total Revenues caused by volatility in these expenses. Operating Income, which is presented in accordance with GAAP in AEP's statements of income, is the most directly comparable GAAP financial measure to the presentation of Gross Margin. AEP's definition of Gross Margin may not be directly comparable to similarly titled financial measures used by other companies.

A detailed discussion of AEP's 2018 results of operations by operating segment can be found in Management's Discussion and Analysis of Financial Condition and Results of Operation section included in the 2018 Annual Report on Form 10-K filed with the SEC on February 21, 2019.

The following table presents Earnings (Loss) Attributable to AEP Common Shareholders by segment:

	Years Ended December 31,		
	2019	2018	2017
	(in millions)		
Vertically Integrated Utilities	$ 982 0	$ 990.5	$ 790 5
Transmission and Distribution Utilities	451 0	527.4	636 4
AEP Transmission Holdco	516.3	369 9	352 1
Generation & Marketing	112 8	135.3	166 0
Corporate and Other	(141.0)	(99 3)	(32.4)
Earnings Attributable to AEP Common Shareholders	$ 1,921 1	$ 1,923 8	$ 1,912.6

2019 Earnings Attributable to AEP Common Shareholders by Segment



Note 2019 Earnings Attributable to AEP Common Shareholders by Segment excludes Corporate and Other which is not considered a reportable segment

AEP CONSOLIDATED

2019 Compared to 2018

Earnings Attributable to AEP Common Shareholders decreased $3 million from $1.924 billion in 2018 to $1.921 billion in 2019 primarily due to:

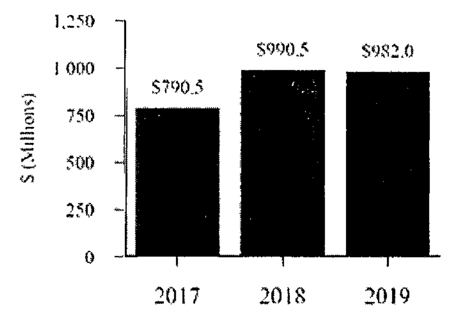
- A decrease in weather-related usage.
- An increase in asset impairments and other related charges.

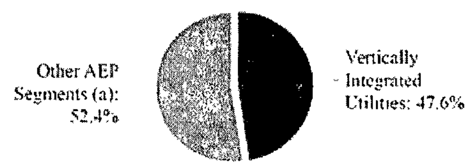
These decreases were partially offset by:

- Favorable rate proceedings in AEP's various jurisdictions.
- An increase in transmission investment, which resulted in higher revenues and income.

AEP's results of operations by reportable segment are discussed below.

VERTICALLY INTEGRATED UTILITIES





(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment

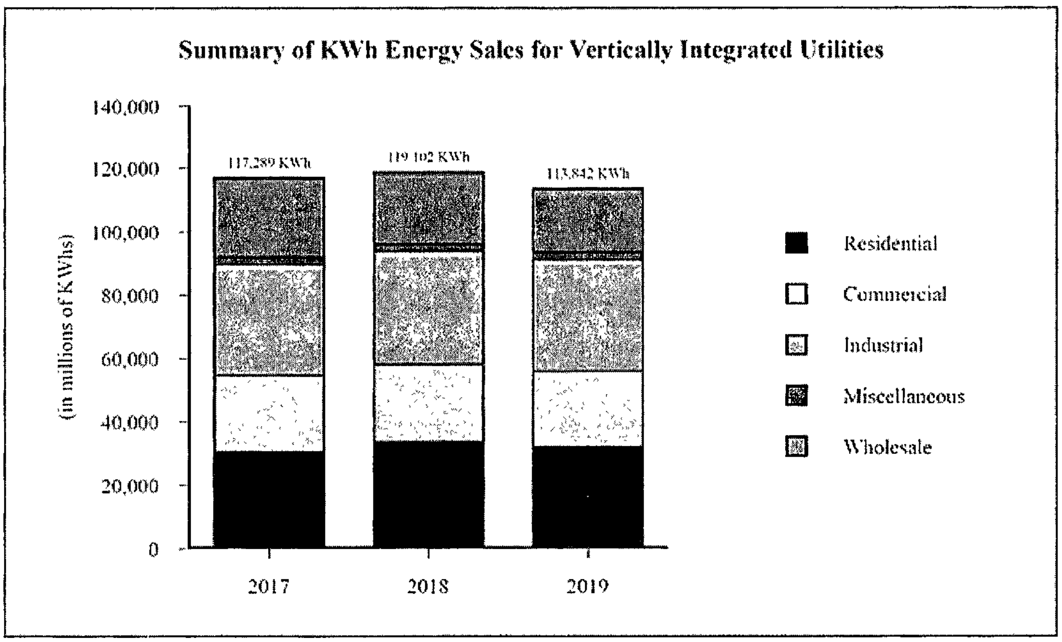
Vertically Integrated Utilities	2019	2018	2017
	Years Ended December 31, (in millions)		
Revenues	$ 9,367.1	$ 9,645.5	$ 9,192.0
Fuel and Purchased Electricity	3,103.1	3,488.9	3,142.7
Gross Margin	6,264.0	6,156.6	6,049.3
Other Operation and Maintenance	2,934.4	2,959.8	2,760.7
Asset Impairments and Other Related Charges	92.9	3.4	33.6
Depreciation and Amortization	1,447.0	1,316.2	1,142.5
Taxes Other Than Income Taxes	460.9	433.2	413.3
Operating Income	1,328.8	1,444.0	1,699.2
Other Income	6.1	17.0	22.0
Allowance for Equity Funds Used During Construction	50.7	35.4	28.0
Non-Service Cost Components of Net Periodic Benefit Cost	67.6	69.9	23.5
Interest Expense	(568.3)	(567.8)	(540.0)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	884.9	998.5	1,232.7
Income Tax Expense (Benefit)	(97.7)	5.7	425.6
Equity Earnings (Loss) of Unconsolidated Subsidiary	3.0	2.7	(3.8)
Net Income	985.6	995.5	803.3
Net Income Attributable to Noncontrolling Interests	3.6	5.0	12.8
Earnings Attributable to AEP Common Shareholders	$ 982.0	$ 990.5	$ 790.5

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	32,359	33,908	30,817
Commercial	23,839	24,452	24,052
Industrial	35,252	35,730	35,043
Miscellaneous	2,302	2,330	2,279
Total Retail (a)	93,752	96,420	92,191
Wholesale (b)	20,090	22,682	25,098
Total KWhs	113,842	119,102	117,289

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

(b) Includes off-system sales, municipalities and cooperatives, unit power and other wholesale customers.

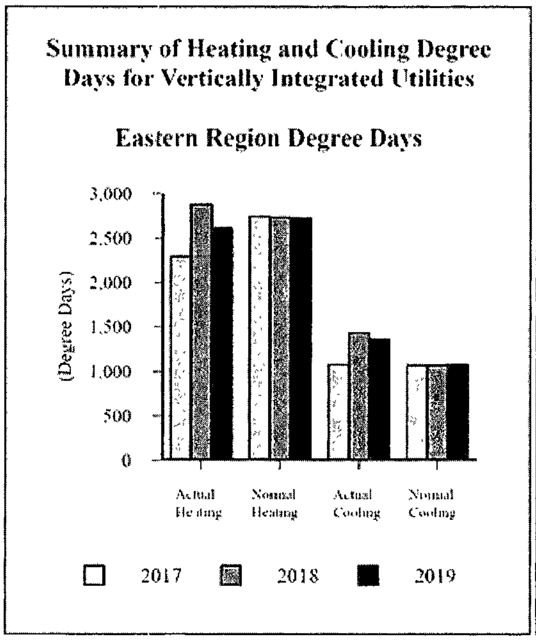


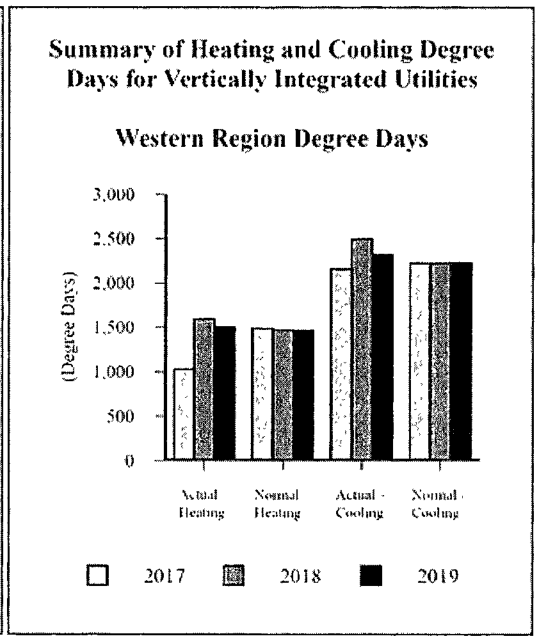
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in degree days)	
Eastern Region			
Actual – Heating (a)	2,617	2,886	2,298
Normal – Heating (b)	2,732	2,738	2,746
Actual – Cooling (c)	1,369	1,443	1,088
Normal – Cooling (b)	1,092	1,083	1,078
Western Region			
Actual – Heating (a)	1,512	1,599	1,040
Normal – Heating (b)	1,473	1,475	1,494
Actual – Cooling (c)	2,328	2,502	2,164
Normal – Cooling (b)	2,240	2,230	2,229

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.





2019 Compared to 2018

**Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Vertically Integrated Utilities
(in millions)**

Year Ended December 31, 2018	$	990.5
Changes in Gross Margin:		
Retail Margins		134.1
Margins from Off-system Sales		(16.0)
Transmission Revenues		(14.0)
Other Revenues		3.3
Total Change in Gross Margin		107.4
Changes in Expenses and Other:		
Other Operation and Maintenance		25.4
Asset Impairments and Other Related Charges		(89.5)
Depreciation and Amortization		(130.8)
Taxes Other Than Income Taxes		(27.7)
Other Income		(10.9)
Allowance for Equity Funds Used During Construction		15.3
Non-Service Cost Components of Net Periodic Pension Cost		(2.3)
Interest Expense		(0.5)
Total Change in Expenses and Other		(221.0)
Income Tax Expense (Benefit)		103.4
Equity Earnings (Loss) of Unconsolidated Subsidiary		0.3
Net Income Attributable to Noncontrolling Interests		1.4
Year Ended December 31, 2019	$	982.0

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $134 million primarily due to the following:
  - A $91 million increase at APCo and WPCo due to a 2018 reduction in the deferred fuel under recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $30 million increase at APCo in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense at APCo in the prior year.
  - The effect of rate proceedings in AEP's service territories which included:
    - A $112 million increase from rate proceedings at I&M, inclusive of a $24 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
    - A $46 million increase at PSO due to new base rates implemented in April 2019 and March 2018.
    - A $28 million increase at APCo and WPCo primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
    - A $23 million increase related to rider revenues at I&M, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
    - A $21 million increase at APCo and WPCo due to base rate increases in West Virginia implemented in March 2019.
    - A $20 million increase at SWEPCo primarily due to rider and base rate revenue increases in Louisiana and Texas. This increase was offset in other expense items below.
  - A $6 million decrease at I&M in fuel-related expenses due to timing of recovery for fuel and other variable production costs related to wholesale contracts.

These increases were partially offset by:
- A $120 million decrease due to customer refunds related to Tax Reform primarily at APCo, PSO and SWEPCo. This decrease was partially offset in Income Tax Expense (Benefit) below.
- A $102 million decrease in weather-related usage across all regions primarily in the residential and commercial classes.
- A $61 million decrease in weather-normalized retail margins primarily in the eastern region across all classes.

- **Margins from Off-system Sales** decreased $16 million primarily due to mid-year 2018 changes in the Indiana OSS sharing mechanism at I&M and lower volumes across the system.
- **Transmission Revenues** decreased $14 million primarily due to the following:
  - A $40 million decrease in the annual SPP formula rate true-up at SWEPCo.
  - A $19 million decrease at SWEPCo and PSO primarily due to a decrease in SPP Base Plan Funding Revenues.
  - A $5 million decrease due to a $14 million decrease at I&M, partially offset by a $9 million increase at KPCo and WPCo due to the 2018 PJM Transmission formula rate true-up.

  These decreases were partially offset by:
  - An $18 million increase in the net revenue requirement at APCo.
  - A $16 million increase at APCo due to 2018 PJM provisions for refunds.
  - A $16 million increase due to a provision for refund recorded at SWEPCo and PSO in 2018 related to certain transmission assets that management believes should not have been included in the SPP formula rate.

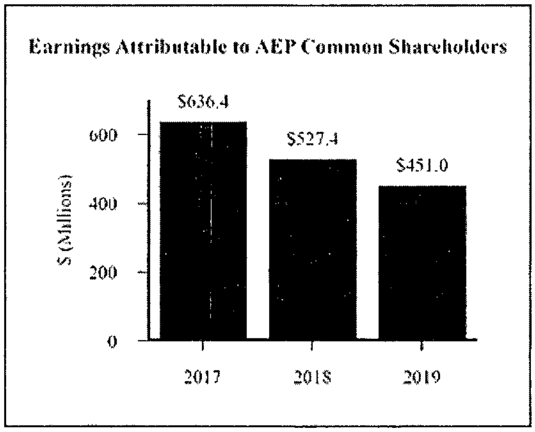
Expenses and Other and Income Tax Expense changed between years as follows:

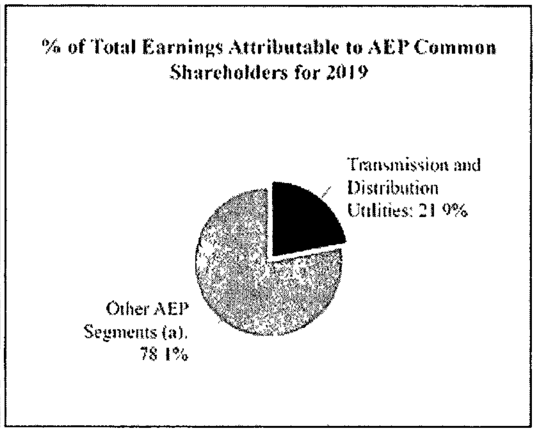
- **Other Operation and Maintenance** expenses decreased $25 million primarily due to the following:
  - A $73 million decrease in planned plant outage and maintenance expenses primarily at I&M, APCo, SWEPCo and KPCo.
  - A $58 million decrease due to SPP transmission services including the annual formula rate true-up.
  - A $40 million decrease due to Wind Catcher Project expenses incurred in 2018 at SWEPCo and PSO.
  - A $40 million decrease at APCo and WPCo due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement. This decrease is partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $25 million decrease in recoverable expenses primarily associated with Energy Efficiency/Demand Response and storm-related expenses fully recovered in rate riders/trackers within Gross Margin above.
  - A $10 million decrease in expense at APCo due to lower current year amortization of certain regulatory assets that were extinguished in August 2018 as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $10 million decrease in estimated expense for claims related to asbestos exposure.

  These decreases were partially offset by:
  - A $131 million increase due to PJM transmission services including the annual formula rate true-up.
  - A $31 million increase in charitable contributions, primarily to the AEP Foundation.
  - A $25 million increase in employee-related expenses.
  - A $15 million increase at APCo and WPCo due to 2019 contributions to benefit low income West Virginia residential customers as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - An $8 million increase due to the modification of the NSR consent decree impacting I&M and AEGCo.
  - A $7 million increase due to North Central Wind Energy Facilities expenses at SWEPCo and PSO.
  - A $4 million increase due to the disallowance of previously recorded capital incentives at SWEPCo as a result of the December 2018 APSC final order.
  - A $4 million increase in accounts receivable factoring expense primarily at I&M and SWEPCo.
- **Asset Impairments and Other Related Charges** increased $90 million primarily due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $131 million primarily due to a higher depreciable base and increased depreciation rates approved at APCo, I&M, PSO and SWEPCo.

- **Taxes Other Than Income Taxes** increased $28 million primarily due to the following:
  - A $15 million increase in property taxes driven by an increase in utility plant.
  - A $13 million increase in West Virginia business and occupational taxes at APCo and WPCo.
- **Other Income** decreased $11 million primarily due the following:
  - A $6 million decrease in carrying charges on certain riders at I&M.
  - A $4 million decrease in affiliated interest income at SWEPCo and I&M due to lower Utility Money Pool investment balances.
- **Allowance for Equity Funds Used During Construction** increased $15 million primarily due to the following:
  - A $10 million increase primarily due to various increases in equity rates at I&M, APCo and PSO and increased projects at I&M.
  - A $3 million increase due to recent FERC audit findings.
  - A $2 million increase due to the FERC's approval of a settlement agreement.
- **Income Tax Expense** decreased $103 million primarily due to additional amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, a decrease in pretax book income and a decrease in state tax expense. The amortization of Excess ADIT is partially offset in Gross Margin and Other Operation and Maintenance expenses above.

TRANSMISSION AND DISTRIBUTION UTILITIES





(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment

Transmission and Distribution Utilities	Years Ended December 31, 2019	2018	2017
		(in millions)	
Revenues	$ 4,482.5	$ 4,653.1	$ 4,419.3
Purchased Electricity	794.3	858.3	835.3
Amortization of Generation Deferrals	65.3	223.9	229.2
Gross Margin	3,622.9	3,570.9	3,354.8
Other Operation and Maintenance	1,628.1	1,541.7	1,199.3
Asset Impairments and Other Related Charges	32.5	—	—
Depreciation and Amortization	789.5	734.1	667.5
Taxes Other Than Income Taxes	575.0	545.3	513.7
Operating Income	597.8	749.8	974.3
Interest and Investment Income	6.6	4.2	7.7
Carrying Costs Income	1.0	1.7	3.6
Allowance for Equity Funds Used During Construction	33.4	29.9	13.2
Non-Service Cost Components of Net Periodic Benefit Cost	30.3	32.3	8.9
Interest Expense	(243.3)	(248.1)	(244.1)
Income Before Income Tax Expense (Benefit)	425.8	569.8	763.6
Income Tax Expense (Benefit)	(25.2)	42.4	127.2
Net Income	451.0	527.4	636.4
Net Income Attributable to Noncontrolling Interests	—	—	—
Earnings Attributable to AEP Common Shareholders	$ 451.0	$ 527.4	$ 636.4

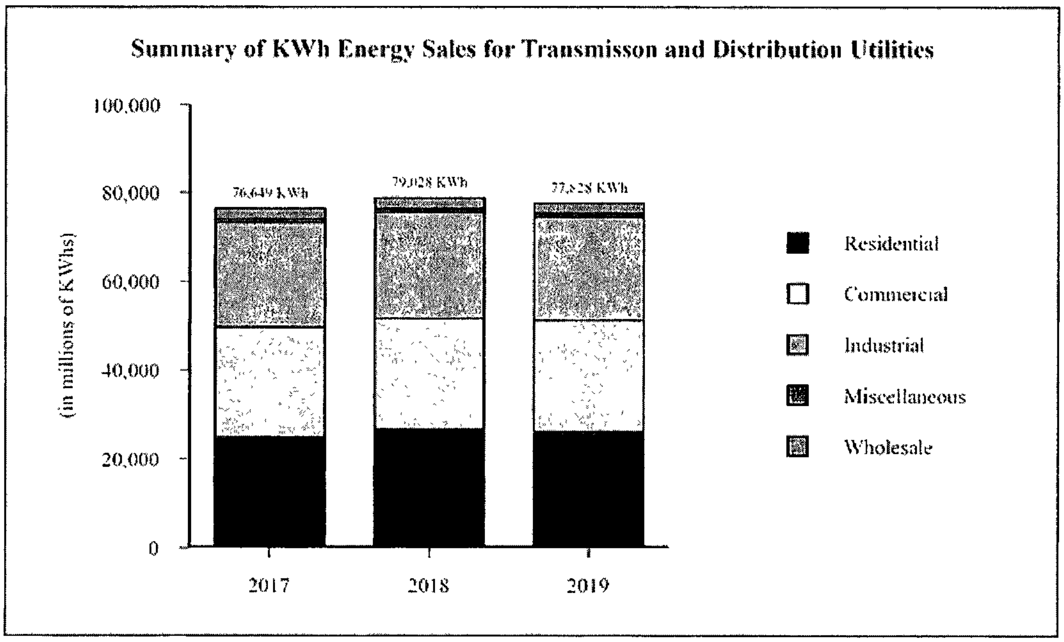
Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	26,407	27,042	25,108
Commercial	25,018	24,877	24,724
Industrial	23,289	23,908	23,673
Miscellaneous	779	760	757
Total Retail (a)(b)	75,493	76,587	74,262
Wholesale (c)	2,335	2,441	2,387
Total KWhs	77,828	79,028	76,649

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

(b) Represents energy delivered to distribution customers.

(c) Primarily Ohio's contractually obligated purchases of OVEC power sold into PJM.

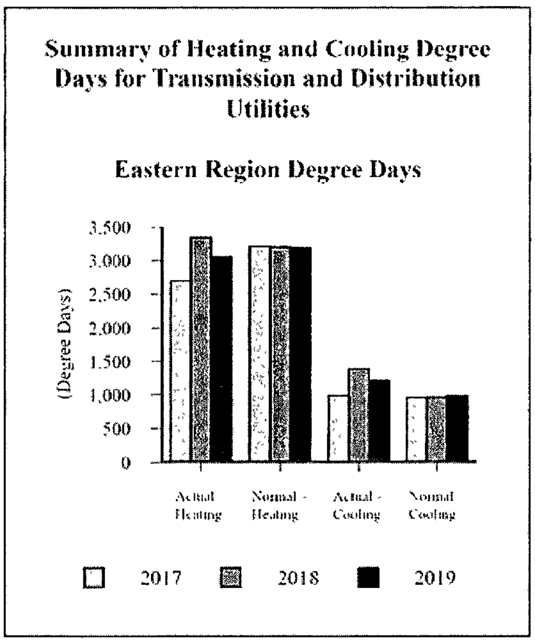


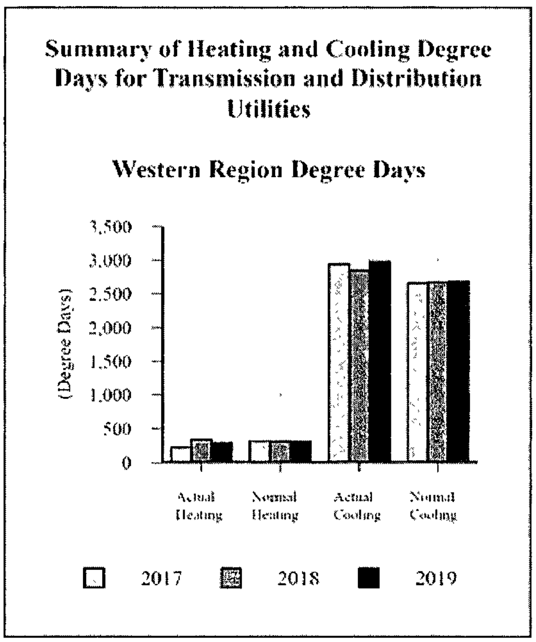
Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues. In general, degree day changes in the eastern region have a larger effect on revenues than changes in the western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Years Ended December 31,		
	2019	2018	2017
	(in degree days)		
Eastern Region			
Actual – Heating (a)	3,071	3,357	2,709
Normal – Heating (b)	3,208	3,215	3,225
Actual – Cooling (c)	1,224	1,402	1,002
Normal – Cooling (b)	992	980	974
Western Region			
Actual – Heating (a)	301	354	239
Normal – Heating (b)	322	325	330
Actual – Cooling (d)	2,989	2,861	2,950
Normal – Cooling (b)	2,699	2,688	2,669

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.





2019 Compared to 2018

**Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Transmission and Distribution Utilities
(in millions)**

Year Ended December 31, 2018	$	527.4
Changes in Gross Margin:		
Retail Margins		(65 2)
Margins from Off-system Sales		11.8
Transmission Revenues		85.6
Other Revenues		19.8
Total Change in Gross Margin		52 0
Changes in Expenses and Other:		
Other Operation and Maintenance		(86.4)
Asset Impairments and Other Related Charges		(32.5)
Depreciation and Amortization		(55.4)
Taxes Other Than Income Taxes		(29 7)
Interest and Investment Income		2.4
Carrying Costs Income		(0.7)
Allowance for Equity Funds Used During Construction		3.5
Non-Service Cost Component of Net Periodic Benefit Cost		(2.0)
Interest Expense		4.8
Total Change in Expenses and Other		(196.0)
Income Tax Expense (Benefit)		67.6
Year Ended December 31, 2019	$	451.0

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity and amortization of generation deferrals were as follows:

- **Retail Margins** decreased $65 million primarily due to the following:
  - A $103 million net decrease in Ohio Basic Transmission Cost Rider revenues and recoverable PJM expenses. This decrease was partially offset in Other Operation and Maintenance expenses below
  - A $30 million decrease due to a provision for refund in the 2019 Texas Base Rate Case.
  - A $25 million decrease in Ohio Deferred Asset Phase-In-Recovery Rider revenues which ended in the second quarter of 2019 This decrease was offset in Depreciation and Amortization expenses below
  - A $22 million decrease in revenues associated with a vegetation management rider in Ohio. This decrease was offset in Other Operation and Maintenance expenses below
  - A $21 million net decrease in margin in Ohio for the Phase-In-Recovery Rider including associated amortizations which ended in the first quarter of 2019.
  - A $21 million net decrease in margin in Ohio for the Rate Stability Rider including associated amortizations which ended in the third quarter of 2019.
  - A $10 million decrease in weather-normalized margins primarily in the residential and commercial classes.

  These decreases were partially offset by.
  - A $58 million increase due to a reversal of a regulatory provision in Ohio.
  - A $41 million increase in revenues associated with Ohio smart grid riders. This increase was partially offset in other expense items below.
  - A $33 million net increase due to 2018 adjustments to the distribution decoupling under-recovery balance as a result of the 2018 Ohio Tax Reform settlement and changes in tax riders. This increase was partially offset in Income Tax Expense (Benefit) below.

  - A $30 million increase due to the recovery of higher current year losses from a power contract with OVEC in Ohio. This increase was offset in Margins from Off-system Sales below.
  - An $11 million increase in Ohio Energy Efficiency/Peak Demand Reduction rider revenues. This increase was offset in Other Operation and Maintenance expenses below.
- **Margins from Off-system Sales** increased $12 million primarily due to the following:
  - A $42 million increase due to higher affiliated PPA revenues in Texas. This increase was partially offset in Other Operation and Maintenance expenses below.

  This increase was partially offset by:
  - A $31 million decrease primarily due to higher current year losses from a power contract with OVEC as a result of the OVEC PPA rider in Ohio. This decrease was offset in Retail Margins above.
- **Transmission Revenues** increased $86 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $20 million primarily due to the following:
  - An $11 million increase primarily due to securitization revenue. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.
  - A $7 million increase primarily due to distribution connection fees and pole attachment revenues in Ohio.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $86 million primarily due to the following:
  - A $68 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - A $64 million increase in expense due to the partial amortization of the Texas Storm Cost Securitization regulatory asset as a result of the final PUCT order in the Texas Storm Cost Case. This increase was offset in Income Tax Expense (Benefit) below.
  - A $49 million increase in affiliated PPA expenses in Texas. This increase was offset in Margins from Off-system Sales above.
  - A $12 million increase due to a charitable contribution to the AEP Foundation.

  These increases were partially offset by:
  - A $117 million decrease in transmission expenses that were fully recovered in rate riders/trackers in Gross Margin above.
- **Asset Impairments and Other Related Charges** increased $33 million due to regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $55 million primarily due to the following:
  - A $68 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets.
  - A $17 million increase in securitization amortizations in Texas. This increase was offset in Other Revenues above and in Interest Expense below.
  - An $11 million increase due to lower deferred equity amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019.
  - A $6 million increase in depreciation expense related to the Oklaunion Power Station.

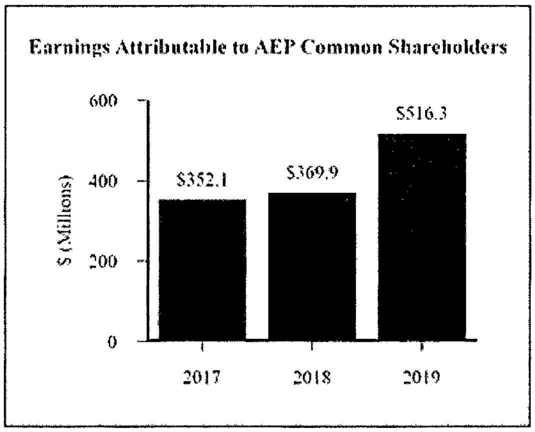
  These increases were partially offset by:
  - A $26 million decrease in Ohio recoverable DIR depreciation expense. This decrease was partially offset in Retail Margins above.
  - A $23 million decrease in amortizations associated with the Deferred Asset Phase-In-Recovery Rider in Ohio which ended in the second quarter of 2019. This decrease was offset in Retail Margins above.
- **Taxes Other Than Income Taxes** increased $30 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets and higher tax rates.
- **Allowance for Equity Funds Used During Construction** increased $4 million primarily due to the following:
  - An $8 million increase in Ohio primarily due to adjustments that resulted from 2019 FERC audit findings.

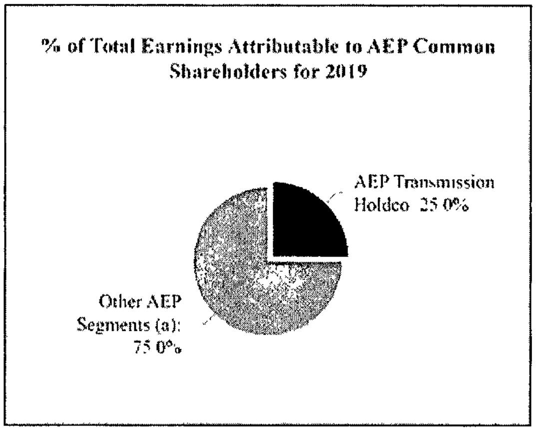
  This increase was partially offset by:
  - A $5 million decrease in the Equity component as a result of higher short-term debt balances, partially offset by increased transmission projects.

- **Interest Expense** decreased $5 million primarily due to the following:
  - A $21 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - An $11 million decrease in expense related to Securitization assets. This decrease was offset in Other Revenues and Depreciation and Amortization expenses above.

  These decreases were partially offset by:
  - A $22 million increase due to higher long-term debt balances.
  - A $2 million increase due to higher short-term debt balances.
- **Income Tax Expense (Benefit)** decreased $68 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019 and a decrease in pretax book income. This decrease was partially offset above in Retail Margins and Other Operation and Maintenance expenses.

AEP TRANSMISSION HOLDCO



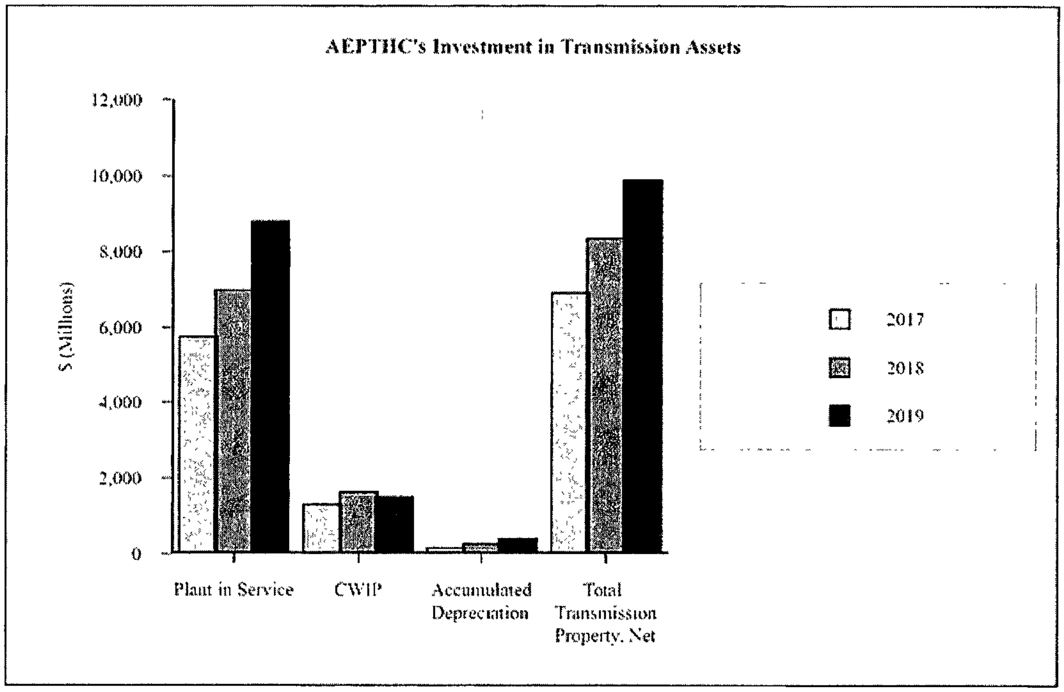


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment

AEP Transmission Holdco	Years Ended December 31, 2019	2018	2017
	(in millions)		
Transmission Revenues	$ 1,073.2	$ 804.1	$ 766.7
Other Operation and Maintenance	119.0	105.6	74.7
Depreciation and Amortization	183.4	137.8	102.2
Taxes Other Than Income Taxes	174.4	142.3	114.0
Operating Income	596.4	418.4	475.8
Other Income	3.4	2.1	1.0
Allowance for Equity Funds Used During Construction	84.3	67.2	52.5
Non-Service Cost Components of Net Periodic Benefit Cost	2.7	2.6	0.3
Interest Expense	(103.3)	(90.7)	(72.8)
Income Before Income Tax Expense and Equity Earnings	583.5	399.6	456.8
Income Tax Expense	136.2	95.3	189.8
Equity Earnings of Unconsolidated Subsidiary	72.8	68.7	88.6
Net Income	520.1	373.0	355.6
Net Income Attributable to Noncontrolling Interests	3.8	3.1	3.5
Earnings Attributable to AEP Common Shareholders	$ 516.3	$ 369.9	$ 352.1

Summary of Investment in Transmission Assets for AEP Transmission Holdco

	December 31, 2019	2018	2017
	(in millions)		
Plant in Service	$ 8,812.2	$ 7,008.4	$ 5,784.6
Construction Work in Progress	1,521.8	1,651.1	1,325.6
Accumulated Depreciation and Amortization	418.9	282.8	176.6
Total Transmission Property, Net	$ 9,915.1	$ 8,376.7	$ 6,933.6



2019 Compared to 2018

**Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from AEP Transmission Holdco
(in millions)**

Year Ended December 31, 2018	$	369.9
Changes in Transmission Revenues:		
Transmission Revenues		269.1
Total Change in Transmission Revenues		269.1
Changes in Expenses and Other:		
Other Operation and Maintenance		(13.4)
Depreciation and Amortization		(45.6)
Taxes Other Than Income Taxes		(32.1)
Other Income		1.3
Allowance for Equity Funds Used During Construction		17.1
Non-Service Cost Components of Net Periodic Pension Cost		0.1
Interest Expense		(12.6)
Total Change in Expenses and Other		(85.2)
Income Tax Expense		(40.9)
Equity Earnings of Unconsolidated Subsidiary		4.1
Net Income Attributable to Noncontrolling Interests		(0.7)
Year Ended December 31, 2019	$	516.3

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and nonaffiliates were as follows:

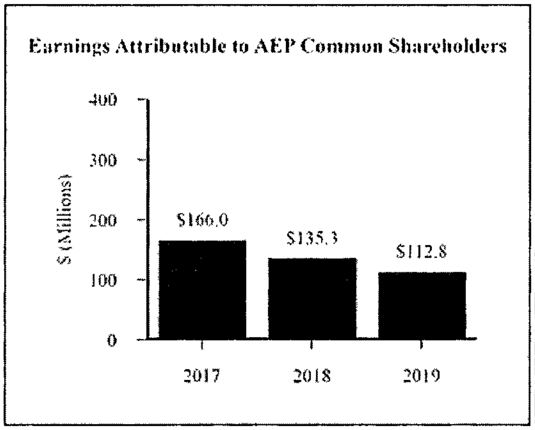
- **Transmission Revenues** increased $269 million primarily due to continued investment in transmission assets.

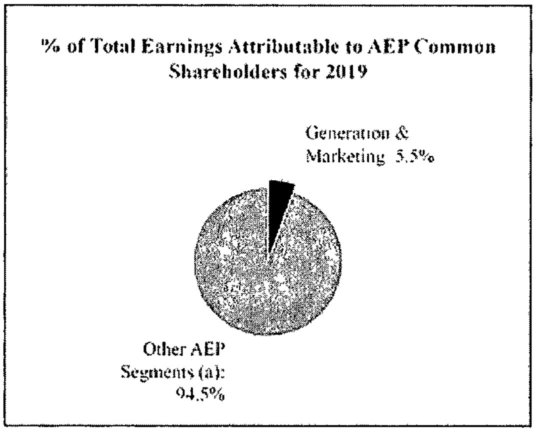
Expenses and Other, Income Tax Expense and Equity Earnings of Unconsolidated Subsidiaries changed between years as follows:

- **Other Operation and Maintenance** expenses increased $13 million primarily due to the following:
  - A $7 million increase due to a charitable contribution to the AEP Foundation.
  - A $6 million increase due to continued investment in transmission assets.
- **Depreciation and Amortization** expenses increased $46 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $32 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $17 million primarily due to the following:
  - An $18 million increase due to higher monthly CWIP balances.
  - A $12 million increase due to the FERC's approval of a settlement agreement.

  These increases were partially offset by:
  - A $13 million decrease due to recent FERC audit findings.
- **Interest Expense** increased $13 million primarily due to higher long-term debt balances.
- **Income Tax Expense** increased $41 million primarily due to higher pretax book income.
- **Equity Earnings of Unconsolidated Subsidiaries** increased $4 million primarily due to higher pretax equity earnings at ETT.

GENERATION & MARKETING



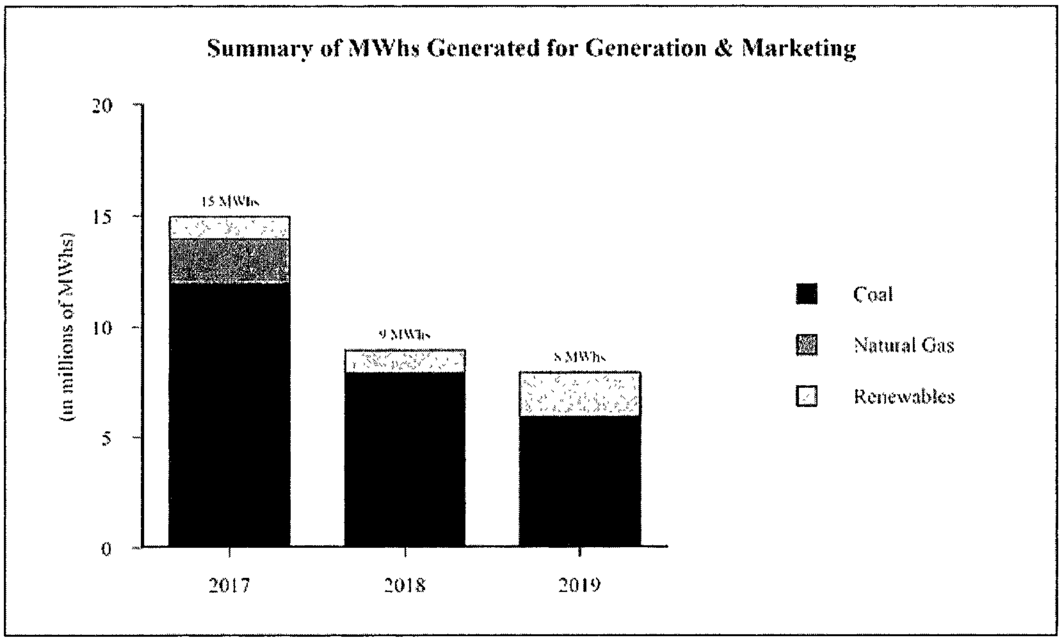


(a) Other AEP Segments excludes Corporate and Other which is not considered a reportable segment

Generation & Marketing	Years Ended December 31, 2019	2018	2017
	(in millions)		
Revenues	$ 1,857.6	$ 1,940.3	$ 1,875.1
Fuel, Purchased Electricity and Other	1,456.2	1,537.3	1,377.2
Gross Margin	401.4	403.0	497.9
Other Operation and Maintenance	223.8	229.3	279.5
Asset Impairments and Other Related Charges	31.0	47.7	53.5
Gain on Sale of Merchant Generation Assets	—	—	(226.4)
Depreciation and Amortization	69.5	41.0	24.2
Taxes Other Than Income Taxes	15.6	13.4	12.1
Operating Income	61.5	71.6	355.0
Interest and Investment Income	7.7	13.1	10.3
Non-Service Cost Components of Net Periodic Benefit Cost	14.9	15.2	8.9
Interest Expense	(30.0)	(14.9)	(18.5)
Income Before Income Tax Expense (Benefit) and Equity Earnings (Loss)	54.1	85.0	355.7
Income Tax Expense (Benefit)	(53.8)	(49.2)	189.7
Equity Earnings (Loss) of Unconsolidated Subsidiaries	(3.8)	0.5	—
Net Income	104.1	134.7	166.0
Net Loss Attributable to Noncontrolling Interests	(8.7)	(0.6)	—
Earnings Attributable to AEP Common Shareholders	$ 112.8	$ 135.3	$ 166.0

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2019	2018	2017
	(in millions of MWhs)		
Fuel Type:			
Coal	6	8	12
Natural Gas	—	—	2
Renewables	2	1	1
Total MWhs	8	9	15



2019 Compared to 2018

**Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Earnings Attributable to AEP Common Shareholders from Generation & Marketing
(in millions)**

Year Ended December 31, 2018	$	135.3
Changes in Gross Margin:		
Merchant Generation		(73.3)
Renewable Generation		31.9
Retail, Trading and Marketing		39.8
Total Change in Gross Margin		(1.6)
Changes in Expenses and Other:		
Other Operation and Maintenance		5.5
Asset Impairments and Other Related Charges		16.7
Depreciation and Amortization		(28.5)
Taxes Other Than Income Taxes		(2.2)
Interest and Investment Income		(5.4)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.3)
Interest Expense		(15.1)
Total Change in Expenses and Other		(29.3)
Income Tax Expense (Benefit)		4.6
Equity Earnings (Loss) of Unconsolidated Subsidiaries		(4.3)
Net Loss Attributable to Noncontrolling Interests		8.1
Year Ended December 31, 2019	$	112.8

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, purchased electricity and certain cost of service for retail operations were as follows:

- **Merchant Generation** decreased $73 million primarily due to the following:
  - A $42 million decrease due to reduced capacity and energy margins.
  - A $17 million decrease due to the retirement of the Stuart Plant in 2018.
  - A $14 million decrease due to the retirement of Conesville Units 5 and 6 in 2019.
- **Renewable Generation** increased $32 million primarily due to the Sempra Renewables LLC acquisition and other renewable projects placed in-service.
- **Retail, Trading and Marketing** increased $40 million due to higher retail margins due to lower market costs and higher delivered volumes and higher marketing activity in 2019.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $6 million primarily due to the retirement of the Stuart Plant and Conesville Units 5 and 6 partially offset by expenses related to the Sempra Renewables LLC acquisition and increased investments in wind farms and renewable energy sources.
- **Asset Impairments and Other Related Charges** decreased $17 million primarily due to a $35 million decrease in impairment charges related to Racine partially offset by a $19 million increase in impairment charges related to the Conesville plant in 2019.
- **Depreciation and Amortization** expenses increased $29 million primarily due to a higher depreciable base from increased investments in renewable energy sources.

- **Interest Expense** increased $15 million primarily due to increased borrowing costs related to the Sempra Renewables LLC acquisition.
- **Income Tax Expense (Benefit)** increased $5 million primarily due to an increase in income and production tax credits related to the Sempra Renewables LLC and Santa Rita East acquisitions. This increase was partially offset by a decrease in parent savings in 2019.
- **Equity Earnings of Unconsolidated Subsidiaries** decreased $4 million primarily due to the Sempra Renewables LLC acquisition.
- **Net Loss Attributed to Noncontrolling Interests** increased $8 million primarily due to the Sempra Renewables LLC acquisition.

CORPORATE AND OTHER

2019 Compared to 2018

Earnings attributable to AEP Common Shareholders from Corporate and Other decreased from a loss of $99 million in 2018 to a loss of $141 million in 2019 primarily due to:

- A $71 million increase in interest expense as a result of increased debt outstanding.
- A $12 million increase in general corporate expenses.
- A $6 million increase in tax expense primarily due to the following:
  - A $23 million increase in state income tax expense related to unitary state filing requirements.
  - An $18 million increase related to the enactment of the Kentucky state tax legislation in the second quarter of 2018.
  - A $5 million increase due to the current year revaluation of AEP's state deferred tax liability as a result of the state income tax filing requirement in Kansas associated with the Sempra Renewables LLC acquisition.

  These increases were partially offset by:
  - A $43 million decrease due to a decrease in the allocation of the parent company loss benefit due to the tax sharing agreement.
- A $5 million write-off of an equity investment and related assets in 2019.

These items were partially offset by:

- A $20 million impairment of an equity investment and related assets in 2018.
- An $18 million increase in interest income from affiliates.
- A $16 million increase in interest income due to a higher return on investments held by EIS.

AEP SYSTEM INCOME TAXES

2019 Compared to 2018

Income Tax Expense decreased $128 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as a result of finalized rate orders in 2019, an increase in income and production tax credits driven by the Sempra Renewables LLC and Santa Rita East acquisitions and a decrease in pretax book income.

FINANCIAL CONDITION

AEP measures financial condition by the strength of its balance sheet and the liquidity provided by its cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2019		2018	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 26,725 5	54 1%	$ 23,346 7	52 7%
Short-term Debt	2,838 3	5 7	1,910 0	4 3
Total Debt	29,563 8	59 8	25,256.7	57.0
AEP Common Equity	19,632 2	39 6	19,028 4	42 9
Noncontrolling Interests	281 0	0.6	31 0	0 1
Total Debt and Equity Capitalization	$ 49,477 0	100 0%	$ 44,316 1	100 0%

AEP's ratio of debt-to-total capital increased from 57.0% to 59.8% as of December 31, 2018 and 2019, respectively, primarily due to an increase in debt to support distribution, transmission and renewable investment growth.

Liquidity

Liquidity, or access to cash, is an important factor in determining AEP's financial stability. Management believes AEP has adequate liquidity under its existing credit facilities. As of December 31, 2019, AEP had a $4 billion revolving credit facility to support its commercial paper program. Additional liquidity is available from cash from operations and a receivables securitization agreement. Management is committed to maintaining adequate liquidity. AEP generally uses short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, leasing agreements, hybrid securities or common stock.

Net Available Liquidity

AEP manages liquidity by maintaining adequate external financing commitments. As of December 31, 2019, available liquidity was $2.1 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup		
Revolving Credit Facility	$ 4,000.0	June 2022
Cash and Cash Equivalents	246 8	
Total Liquidity Sources	4,246.8	
Less AEP Commercial Paper Outstanding	2,110 0	
Net Available Liquidity	$ 2,136 8	

AEP uses its commercial paper program to meet the short-term borrowing needs of its subsidiaries. The program funds a Utility Money Pool, which funds AEP's utility subsidiaries; a Nonutility Money Pool, which funds certain AEP nonutility subsidiaries; and the short-term debt requirements of subsidiaries that are not participating in either money pool for regulatory or operational reasons, as direct borrowers. The maximum amount of commercial paper outstanding during 2019 was $2.2 billion. The weighted-average interest rate for AEP's commercial paper during 2019 was 2.51%.

Other Credit Facilities

An uncommitted facility gives the issuer of the facility the right to accept or decline each request made under the facility. AEP issues letters of credit on behalf of subsidiaries under six uncommitted facilities totaling $405 million. The Registrants' maximum future payments for letters of credit issued under the uncommitted facilities as of December 31, 2019, was $207 million with maturities ranging from January 2020 to December 2020.

Financing Plan

As of December 31, 2019, AEP had $1.6 billion of long-term debt due within one year. This included $431 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current and $392 million of securitization bonds and DCC Fuel notes. Management plans to refinance the majority of the maturities due within one year on a long-term basis.

Securitized Accounts Receivables

AEP receivables securitization agreement provides a commitment of $750 million from bank conduits to purchase receivables and expires in July 2021.

Debt Covenants and Borrowing Limitations

AEP's credit agreements contain certain covenants and require it to maintain a percentage of debt-to-total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually-defined in AEP's credit agreements. Debt as defined in the revolving credit agreement excludes securitization bonds and debt of AEP Credit. As of December 31, 2019, this contractually-defined percentage was 57.4%. Non-performance under these covenants could result in an event of default under these credit agreements. In addition, the acceleration of AEP's payment obligations, or the obligations of certain of AEP's major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of AEP's non-exchange-traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under AEP's non-exchange-traded commodity contracts would not cause an event of default under its credit agreements.

The revolving credit facility does not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders and AEP manages its borrowings to stay within those authorized limits.

Equity Units

In March 2019, AEP issued 16.1 million Equity Units initially in the form of corporate units, at a stated amount of $50 per unit, for a total stated amount of $805 million. Net proceeds from the issuance were approximately $785 million. Each corporate unit represents a 1/20 undivided beneficial ownership interest in $1,000 principal amount of AEP's 3.40% Junior Subordinated Notes due in 2024 and a forward equity purchase contract which settles after three years in 2022. The proceeds from this issuance were used to support AEP's overall capital expenditure plans including the recent acquisition of Sempra Renewables LLC. See Note 14 - Financing Activities for additional information.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.70 per share in January 2020. Future dividends may vary depending upon AEP's profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Parent's income primarily derives from common stock equity in the earnings of its utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of the subsidiaries to transfer funds to Parent in the form of dividends. Management does not believe these restrictions will have any significant impact on its ability to access cash to meet the payment of dividends on its common stock. See "Dividend Restrictions" section of Note 14 for additional information.

Credit Ratings

AEP and its utility subsidiaries do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but its access to the commercial paper market may depend on its credit ratings. In addition, downgrades in AEP's credit ratings by one of the rating agencies could increase its borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject AEP to additional collateral demands under adequate assurance clauses under its derivative and non-derivative energy contracts.

CASH FLOW

AEP relies primarily on cash flows from operations, debt issuances and its existing cash and cash equivalents to fund its liquidity and investing activities. AEP's investing and capital requirements are primarily capital expenditures, repaying of long-term debt and paying dividends to shareholders. AEP uses short-term debt, including commercial paper, as a bridge to long-term debt financing. The levels of borrowing may vary significantly due to the timing of long-term debt financings and the impact of fluctuations in cash flows.

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in millions)	
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$ 444 1	$ 412 6	$ 403 5
Net Cash Flows from Operating Activities	4,270 1	5,223 2	4,270 4
Net Cash Flows Used for Investing Activities	(7,144 5)	(6,353.6)	(3,656.4)
Net Cash Flows from (Used for) Financing Activities	2,862 9	1,161 9	(604 9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(11.5)	31 5	9.1
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 432 6	$ 444 1	$ 412 6

Operating Activities

	Years Ended December 31,		
	2019	**2018**	**2017**
		(in millions)	
Net Income	$ 1,919.8	$ 1,931.3	$ 1,928.9
Non-Cash Adjustments to Net Income (a)	2,685.7	2,400.0	2,822 6
Mark-to-Market of Risk Management Contracts	(29 2)	(66.4)	(23.3)
Pension Contributions to Qualified Plan Trust	—	—	(93 3)
Property Taxes	(73 8)	(59.1)	(29.5)
Deferred Fuel Over/Under Recovery, Net	85 2	189.7	84 4
Recovery of Ohio Capacity Costs, Net	34 1	67.7	83 2
Refund of Global Settlement	(16 5)	(5 5)	(98 2)
Change in Other Noncurrent Assets	(97.4)	119 8	(423 9)
Change in Other Noncurrent Liabilities	(116 1)	129 0	181 7
Change in Certain Components of Working Capital	(121.7)	516.7	(162 2)
Net Cash Flows from Operating Activities	$ 4,270 1	$ 5,223 2	$ 4,270 4

(a) Non-Cash Adjustments to Net Income includes Depreciation and Amortization, Rockport Plant Unit 2 Operating Lease Amortization, Deferred Income Taxes, Asset Impairments and Other Related Charges, Allowance for Equity Funds Used During Construction, Amortization of Nuclear Fuel, Pension and Postemployment Benefit Reserves and Gain on Sale of Merchant Generation Assets

2019 Compared to 2018

Net Cash Flows from Operating Activities decreased by $953 million primarily due to the following:

- A $638 million decrease in cash from Changes in Certain Components of Working Capital. This decrease was primarily due to an increase in fuel, material and supplies balances as a result of mild winter weather, the addition of operating lease payments due to the adoption of ASU 2016-02, higher employee-related benefits and revenue refunds related to Tax Reform. These decreases were partially offset by timing of accounts receivables.
- A $245 million decrease in cash from Change in Other Noncurrent Liabilities primarily due to increases in revenue refunds related to Tax Reform and Ohio regulatory liabilities.
- A $217 million decrease in cash from Changes in Other Noncurrent Assets primarily due to a change in regulatory assets as a result of AEP subsidiaries with rider recovery mechanisms. See Note 4 - Rate Matters for additional information.
- A $105 million decrease in cash from Deferred Fuel Over/Under Recovery, Net primarily due to the full recovery of the Ohio Phase-in-Recovery Rider and prior year reduction of ENEC balances at APCo and WPCo as a result of the 2018 West Virginia Tax Reform Order, partially offset by net rate and weather fluctuations across jurisdictions. See Note 4 - Rate Matters for additional information.

These decreases in cash were partially offset by:

- A $274 million increase in cash from Net Income, after non-cash adjustments. See Results of Operations for further detail.

Investing Activities

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Construction Expenditures	$ (6,051 4)	$ (6,310 9)	$ (5,691.3)
Acquisitions of Nuclear Fuel	(92 3)	(46 1)	(108 0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918 4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159 6
Other	(82 4)	3 4	(16.7)
Net Cash Flows Used for Investing Activities	$ (7,144 5)	$ (6,353 6)	$ (3,656.4)

2019 Compared to 2018

Net Cash Flows Used for Investing Activities increased by $791 million primarily due to the following:

- A $918 million increase due to the acquisition of Sempra Renewables LLC and Santa Rita East. The $918 million represents a cash payment of $936 million, net of cash and restricted cash acquired of $18 million. See Note 7 - Acquisitions, Dispositions and Impairments for additional information.

This increase in the use of cash was partially offset by:

- A $260 million decrease in construction expenditures primarily due to decreases in Generation & Marketing.

Financing Activities

	Years Ended December 31,		
	2019	2018	2017
		(in millions)	
Issuance of Common Stock	$ 65 3	$ 73 6	$ 12 2
Issuance/Retirement of Debt, Net	4,244 1	2,435 1	691 8
Dividends Paid on Common Stock	(1,350 0)	(1,255 5)	(1,191 9)
Other	(96 5)	(91 3)	(117.0)
Net Cash Flows from (Used for) Financing Activities	$ 2,862 9	$ 1,161 9	$ (604.9)

2019 Compared to 2018

Net Cash Flows from Financing Activities increased by $1.7 billion primarily due to the following:

- A $1.6 billion increase in cash due to decreased retirements of long-term debt. See Note 14 - Financing Activities for additional information.
- A $657 million increase in cash from short-term debt primarily due to increased borrowings of commercial paper. See Note 14 - Financing Activities for additional information.

These increases in cash were partially offset by:

- A $409 million decrease in issuance of long-term debt. See Note 14 - Financing Activities for additional information.

The following financing activities occurred during 2019:

AEP Common Stock:

- During 2019, AEP issued 924 thousand shares of common stock under the incentive compensation, employee saving and dividend reinvestment plans and received net proceeds of $65 million.

Debt:

- During 2019, AEP issued approximately $4.6 billion of long-term debt, including $2.7 billion of senior unsecured notes at interest rates ranging from 3.15% to 4.5%, $805 million of junior subordinated debenture note at interest rate of 3.4%, $771 million of pollution control bonds at interest rates ranging from 1.35% to 2.60%, and $375 million of other debt at various interest rates. The proceeds from these issuances were used to fund long-term debt maturities and construction programs.
- During 2019, AEP entered into interest rate derivatives with notional amounts totaling $125 million that were designated as cash flow hedges. As of December 31, 2019, AEP had a total notional amount of $125 million of interest rate derivatives designated as cash flow hedges. During 2019, settlements of AEP's interest rate derivatives designated as fair value hedges resulted in net cash paid of $1.5 million. As of December 31, 2019, AEP had a total notional amount of $500 million of outstanding interest rate derivatives designated as fair value hedges.

In 2020:

In January and February 2020, AEP Texas retired $111 million and $3 million, respectively, of Securitization Bonds.

In January and February 2020, I&M retired $8 million and $5 million, respectively, of Notes Payable related to DCC Fuel.

In January 2020, Transource Energy issued $4 million of variable rate Other Long-term Debt due in 2023.

In February 2020, APCo retired $12 million of Securitization Bonds.

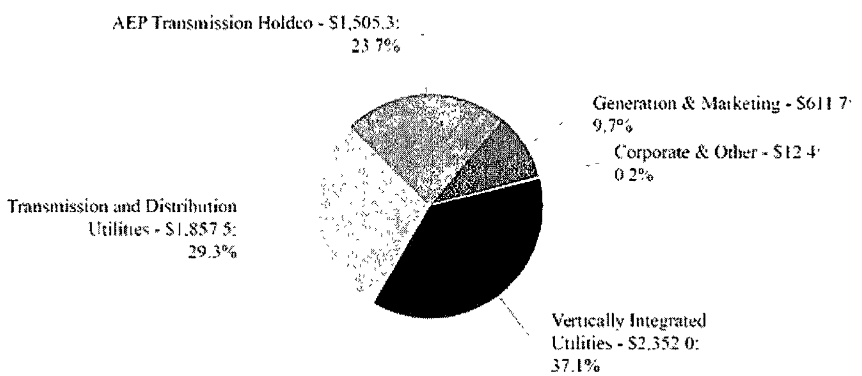
BUDGETED CAPITAL EXPENDITURES

Management forecasts approximately $6.3 billion of capital expenditures in 2020. For the four year period, 2021 through 2024, management forecasts capital expenditures of $26.6 billion. Capital expenditures related to North Central Wind Energy Facilities are excluded from these budgeted amounts. The expenditures are generally for transmission, generation, distribution, regulated and contracted renewables, and required environmental investment to comply with the Federal EPA rules. Estimated capital expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. Management expects to fund these capital expenditures through cash flows from operations and financing activities. Generally, the Registrant Subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2020 estimated capital expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Segment	**Environmental**	**Generation**	**Transmission**	**Distribution**	**Other (a)**	**Total**
			(in millions)			
Vertically Integrated Utilities	$ 165 1	$ 277 2	$ 701 0	$ 899 6	$ 309 1	$ 2,352 0
Transmission and Distribution Utilities	—	1 8	765.3	870.9	219 5	1,857 5
AEP Transmission Holdco	—	—	1,452.0	—	53 3	1,505 3
Generation & Marketing	11 0	571 8	—	—	28 9	611 7
Corporate and Other	—	—	—	—	12 4	12 4
Total	$ 176 1	$ 850.8	$ 2,918.3	$ 1,770 5	$ 623 2	$ 6,338 9

(a) Amount primarily consists of facilities, software and telecommunications.

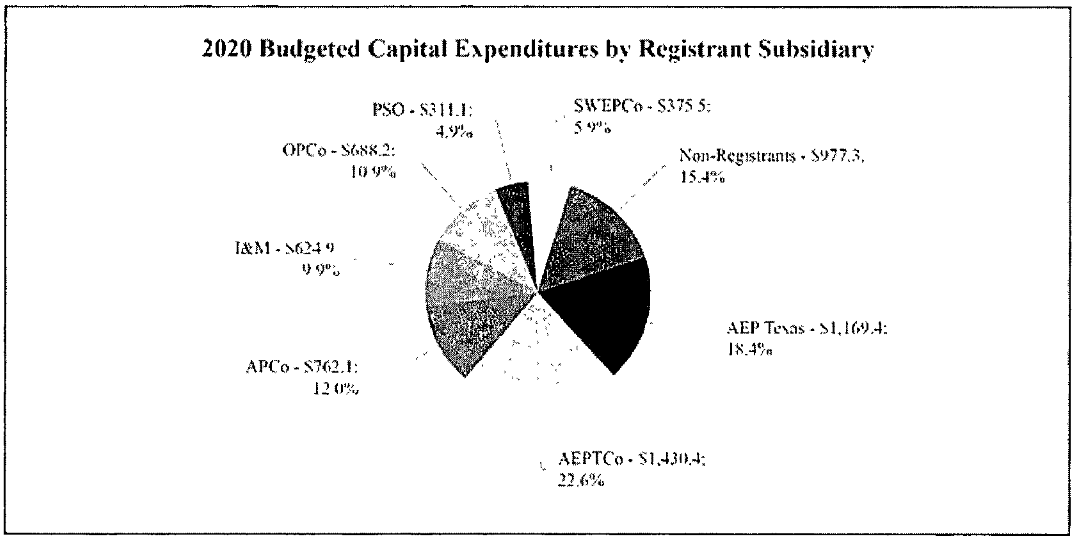
2020 Budgeted Capital Expenditures by Business Segment



The 2020 estimated capital expenditures by Registrant Subsidiary include distribution, transmission and generation related investments, as well as expenditures for compliance with environmental regulations as follows:

	2020 Budgeted Capital Expenditures					
Company	Environmental	Generation	Transmission	Distribution	Other (a)	Total
			(in millions)			
AEP Texas	$ —	$ 1.8	$ 629 4	$ 443.5	$ 94 7	$ 1,169.4
AEPTCo	—	—	1,374 1	—	56 3	1,430 4
APCo	37.3	43 4	339 7	267.7	74 0	762.1
I&M	33 4	153 8	83 6	248 7	105 4	624 9
OPCo	—	—	135.9	427 4	124 9	688.2
PSO	6 0	21 2	49.7	183 8	50 4	311 1
SWEPCo	40.1	39.5	126.5	122 6	46.8	375 5

(a) Amount primarily consists of facilities, software and telecommunications



CONTRACTUAL OBLIGATION INFORMATION

AEP's contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in the footnotes. The following table summarizes AEP's contractual cash obligations as of December 31, 2019:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 2,838 3	$ —	$ —	$ —	$ 2,838 3
Interest on Fixed Rate Portion of Long-term Debt (b)	28 8	45 2	31 7	29 3	135 0
Fixed Rate Portion of Long-term Debt (c)	1,070 4	4,238 3	1,271 3	18,863.1	25,443 1
Variable Rate Portion of Long-term Debt (d)	528 3	799 0	175 1	—	1,502 4
Finance Lease Obligations (e)	72 7	121 3	107.0	64.4	365 4
Operating Lease Obligations (e)	269 9	499 2	136.8	169 7	1,075 6
Fuel Purchase Contracts (f)	1,047 0	1,105 0	234.4	111 4	2,497 8
Energy and Capacity Purchase Contracts	227 8	353 2	273 5	1,080 0	1,934 5
Construction Contracts for Capital Assets (g)	2,121.2	3,752 4	2,992 8	3,382.7	12,249 1
Total	$ 8,204 4	$ 10,913.6	$ 5,222 6	$ 23,700 6	$ 48,041 2

(a) Represents principal only, excluding interest
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2019 and do not reflect anticipated future refinancing, early redemptions or debt issuances
(c) See "Long-term Debt" section of Note 14 for additional information. Represents principal only, excluding interest
(d) See "Long-term Debt" section of Note 14 for additional information Represents principal only, excluding interest Variable rate debt had interest rates that ranged between 1.67% and 3 20% as of December 31, 2019
(e) See Note 13 - Leases for additional information
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel
(g) Represents only capital assets for which there are signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs

AEP's pension funding requirements are not included in the above table. As of December 31, 2019, AEP expects to make contributions to the pension plans totaling $6 million in 2020. Estimated contributions of $119 million in 2021 and $123 million in 2022 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, the pension plans were 95.8% funded as of December 31, 2019. See "Estimated Future Benefit Payments and Contributions" section of Note 8 for additional information.

In addition to the amounts disclosed in the contractual cash obligations table above, standby letters of credit are entered into with third-parties. These letters of credit are issued in the ordinary course of business and cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. There is no collateral held in relation to any guarantees in excess of the ownership percentages. In the event any letters of credit are drawn, there is no recourse to third-parties. See "Letters of Credit" section of Note 6 for additional information.

SIGNIFICANT TAX LEGISLATION

In December 2017, Tax Reform legislation was signed into law. Tax Reform includes significant changes to the Internal Revenue Code of 1986, as amended, including lowering the corporate federal income tax rate from 35% to 21%. As a result of this rate change, the Registrants' deferred tax assets and liabilities were remeasured using the newly enacted rate of 21% in December 2017. In December 2019, a tax extenders bill was signed into law to extend wind PTCs an additional year. Wind projects that begin construction in 2020 are now eligible for a 60% PTC or alternatively an 18% ITC in lieu of a PTC. See "Federal Tax Reform and Legislation" and "State Tax Legislation" sections of Note 12 for additional information.

CYBER SECURITY

The electric utility industry is an identified critical infrastructure function with mandatory cyber security requirements under the authority of FERC. The North American Electric Reliability Corporation (NERC), which FERC certified as the nation's Electric Reliability Organization, developed mandatory critical infrastructure protection cyber security reliability standards. AEP began participating in the NERC grid security and emergency response exercises, GridEx, in 2013 and continues to participate in the bi-yearly exercises. These efforts, led by NERC, test and further develop the coordination, threat sharing and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid. The operations of AEP's electric utility subsidiaries are subject to extensive and rigorous mandatory cyber and physical security requirements that are developed and enforced by NERC to protect grid security and reliability. AEP's Enterprise Security program uses the National Institute of Standards and Technology Cybersecurity Framework as a guideline.

Critical cyber assets, such as data centers, power plants, transmission operations centers and business networks are protected using multiple layers of cyber security and authentication. Cyber hackers have been successful in breaching a number of very secure facilities, including federal agencies, banks and retailers. As understanding of these events develop, AEP has adopted a defense in depth approach to cyber security and continually assesses its cyber security tools and processes to determine where to strengthen its defenses. These strategies include monitoring, alerting and emergency response, forensic analysis, disaster recovery and criminal activity reporting. This approach allows AEP to deal with threats in real time.

AEP has undertaken a variety of actions to monitor and address cyber related risks. Cyber security and the effectiveness of AEP's cyber security processes are reviewed annually with the Board of Directors and at several meetings with the Audit Committee throughout the year. AEP's strategy for managing cyber related risks is integrated within its enterprise risk management processes. AEP enterprise security continually adjusts staff and resources in response to the evolving threat landscape. In addition, AEP maintains cyber liability insurance to cover certain damages caused by cyber incidents.

AEP's Chief Security Officer (CSO) leads the cyber security and physical security teams and is responsible for the design, implementation and execution of AEP's security risk management strategy, which includes cyber security. AEP operates a 24/7 Cyber Security Intelligence and Response Center (cyber security team) responsible for monitoring the AEP System for cyber risks and threats. Among other things, the CSO and the cyber security team actively monitor best practices, perform penetration testing, lead response exercises and internal campaigns and provide training and communication across the organization.

The cyber security team constantly scans the AEP System for risks and threats. AEP also continually reviews its business continuity plan to develop an effective recovery strategy that seeks to decrease response times, limit financial impacts and maintain customer confidence during any business interruption. AEP has implemented a third-party risk governance program to identify potential risks introduced through third-party relationships, such as vendors, software and hardware manufacturers or professional service providers. As warranted, AEP obtains certain contractual security guarantees and assurances with these third-party relationships to help ensure the security and safety of its information. The cyber security team works closely with a broad range of departments, including legal, regulatory, corporate communications and audit services and information technology.

The cyber security team collaborates with partners from both industry and government, and routinely participates in industry-wide programs that exchange knowledge of threats with utility peers, industry and federal agencies. AEP is an active member of a number of industry specific threat and information sharing communities including the Department of Homeland Security and the Electricity Information Sharing and Analysis Center. AEP continues to work with nonaffiliated entities to do penetration testing and to design and implement appropriate remediation strategies.

There can be no assurance, however, that these efforts will be effective to prevent interruption of services or other damages to AEP's business or operations in connection with any cyber-related incident.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING STANDARDS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. Management considers an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

Management discusses the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

Management believes that the current assumptions and other considerations used to estimate amounts reflected in the financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

The Registrants' financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

The Registrants recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, the timing of expense and income recognition is matched with regulated revenues. Liabilities are also recorded for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, regulatory assets are recorded on the balance sheets. Management reviews the probability of recovery at each balance sheet date and whenever new events occur. Similarly, regulatory liabilities are recorded when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, that regulatory asset is written-off as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect of Different Assumptions Used

A change in the above assumptions may result in a material impact on net income. See Note 5 - Effects of Regulation for additional information related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

AEP recognizes revenues from customers as the performance obligations of delivering energy to customers are satisfied. The determination of sales to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. PSO and SWEPCo do not include the fuel portion in unbilled revenue in accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas.

Accrued unbilled revenues for the Vertically Integrated Utilities segment were $248 million and $255 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Vertically Integrated Utilities segment were $(7) million, $(23) million and $37 million for the years ended December 31, 2019, 2018 and 2017, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $166 million and $178 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Transmission and Distribution Utilities segment were $(12) million, $(24) million and $11 million for the years ended December 31, 2019, 2018 and 2017, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rates.

Accrued unbilled revenues for the Generation & Marketing segment were $75 million and $59 million as of December 31, 2019 and 2018, respectively. The changes in unbilled electric utility revenues for AEP's Generation & Marketing segment were $16 million, $5 million and $5 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Assumptions and Approach Used

For each Registrant except AEPTCo, the monthly estimate for unbilled revenues is based upon a primary computation of net generation (generation plus purchases less sales) less the current month's billed KWh and estimated line losses, plus the prior month's unbilled KWh. However, due to the potential for meter reading issues, meter drift and other anomalies, a secondary computation is made, based upon an allocation of billed KWh to the current month and previous month, on a billing cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The two methodologies are evaluated to confirm that they are not statistically different.

For AEP's Generation & Marketing segment, management calculates unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect of Different Assumptions Used

If the two methodologies used to estimate unbilled revenue are statistically different, a limiter adjustment is made to bring the primary computation within one standard deviation of the secondary computation. Additionally, significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the estimate of unbilled revenue.

Accounting for Derivative Instruments

Nature of Estimates Required

Management considers fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

The Registrants measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, the fair value is estimated based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

The Registrants reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. Liquidity adjustments are calculated by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. Credit adjustments on risk management contracts are calculated using estimated default probabilities and recovery rates relative to the counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, management assesses hedge effectiveness and evaluates a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information see Note 10 - Derivatives and Hedging and Note 11 - Fair Value Measurements. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for AEP's fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance and "Regulated Operations" accounting guidance, the Registrants evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable. Such events or changes in circumstance include planned abandonments, probable disallowances for rate-making purposes of assets determined to be recently completed plant and assets that meet the held-for-sale criteria. The Registrants utilize a group composite method of depreciation to estimate the useful lives of long-lived assets.

An impairment evaluation of a long-lived, held and used asset may result from an abandonment, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount of the asset is not recoverable, the Registrants record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. Any impairment charge is recorded as a reduction to earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, the Registrants estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions on the use of the asset. The Registrants perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of the asset can vary if different estimates and assumptions are used in the applied valuation techniques. Estimates for depreciation rates contemplate the history of interim capital replacements and the amount of salvage expected. In cases of impairment, the best estimate of fair value was made using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, the timing and terms of the transactions and management's analysis of the benefits of the transaction.

Pension and OPEB

AEP maintains a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). AEP also sponsors OPEB plans to provide health and life insurance benefits for retired employees. The Pension Plans and OPEB plans are collectively referred to as the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 8 - Benefit Plans for information regarding costs and assumptions for the Plans.

The following table shows the net periodic cost (credit) of the Plans:

	Years Ended December 31,		
Net Periodic Cost (Credit)	**2019**	**2018**	**2017**
		(in millions)	
Pension Plans	$ 61.5	$ 82.9	$ 98.6
OPEB	(80.7)	(101.8)	(63.2)

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2020, management evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. Management also considered historical returns of the investment markets and tax rates which affect a portion of the OPEB plans' assets. Management anticipates that the investment managers employed for the Plans will invest the assets to generate future returns averaging 5.75% for the Qualified Plan and 5.5% for the OPEB plans.

The expected long-term rate of return on the Plans' assets is based on management's targeted asset allocation and expected investment returns for each investment category. Assumptions for the Plans are summarized in the following table:

	Pension Plans		OPEB	
	2020 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2020 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	30%	7.70%	48%	7.27%
Fixed Income	54	4.18	50	3.85
Other Investments	15	7.96	—	—
Cash and Cash Equivalents	1	2.17	2	2.17
Total	100%		100%	

Management regularly reviews the actual asset allocation and periodically rebalances the investments to the targeted allocation. Management believes that 5.75% for the Qualified Plan and 5.5% for the OPEB plans are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 15.81% for the year ended December 31, 2019 and an actual loss of 2.10% for the year ended December 31, 2018. The OPEB plans' assets had an actual gain of 20.93% for the year ended December 31, 2019 and an actual loss of 6.38% for the year ended December 31, 2018. Management will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

AEP bases the determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2019, AEP had cumulative gains of approximately $209 million for the Qualified Plan that remain to be recognized in the calculation of the market-related value of assets. These unrecognized market-related net actuarial gains may result in increases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that AEP utilizes for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds is constructed with cash flows matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan. The discount rate as of December 31, 2019 under this method was 3.25% for the Qualified Plan, 3.15% for the Nonqualified Plans and 3.3% for the OPEB plans. Due to the effect of the unrecognized net actuarial losses and based on an expected rate of return on the Pension Plans' assets of 5.75%, discount rates of 3.25% and 3.15% and various other assumptions, management estimates that the pension costs for the Pension Plans will approximate $107 million, $94 million and $81 million in 2020, 2021 and 2022, respectively. Based on an expected rate of return on the OPEB plans' assets of 5.5%, a discount rate of 3.3% and various other assumptions, management estimates OPEB plan credits will approximate $110 million, $111 million and $112 million in 2020, 2021 and 2022, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of AEP's Pension Plans' assets increased to $5.0 billion as of December 31, 2019 from $4.7 billion as of December 31, 2018 primarily due to higher investment returns. During 2019, the Qualified Plan paid $361 million and the Nonqualified Plans paid $6 million in benefits to plan participants. The value of AEP's OPEB plans' assets increased to $1.8 billion as of December 31, 2019 from $1.5 billion as of December 31, 2018 primarily due to higher investment returns. The OPEB plans paid $113 million in benefits to plan participants during 2019.

Nature of Estimates Required

AEP sponsors pension and OPEB plans in various forms covering all employees who meet eligibility requirements. These benefits are accounted for under "Compensation" and "Plan Accounting" accounting guidance. The measurement of pension and OPEB obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and OPEB expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		OPEB	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2019 Benefit Obligations				
Discount Rate	$ (258.1)	$ 283.3	$ (64.4)	$ 71.0
Compensation Increase Rate	26.3	(24.3)	NA	NA
Cash Balance Crediting Rate	71.4	(66.1)	NA	NA
Health Care Cost Trend Rate	NA	NA	15.7	(15.3)
Effect on 2019 Periodic Cost				
Discount Rate	$ (12.7)	$ 13.9	$ (3.2)	$ 3.5
Compensation Increase Rate	5.3	(4.9)	NA	NA
Cash Balance Crediting Rate	13.5	(12.4)	NA	NA
Health Care Cost Trend Rate	NA	NA	2.0	(1.9)
Expected Return on Plan Assets	(23.7)	23.7	(7.5)	7.5

NA Not applicable.

ACCOUNTING STANDARDS

See Note 2 - New Accounting Standards for information related to accounting standards adopted in 2019 and standards effective in the future.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

The Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates.

The Transmission and Distribution Utilities segment is exposed to energy procurement risk and interest rate risk.

The Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM, SPP and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risks which may be subject to capacity risk, credit risk as well as interest rate risk. These risks represent the risk of loss that may impact this segment due to changes in the underlying market prices or rates. In addition, the Generation & Marketing segment is also exposed to certain market risks as a power producer and through transactions in wholesale electricity, natural gas and marketing contracts.

Management employs risk management contracts including physical forward and financial forward purchase-and-sale contracts. Management engages in risk management of power, capacity, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. As a result, AEP is subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply and Finance groups in accordance with established risk management policies as approved by the Finance Committee of the Board of Directors. AEPSC's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations, Senior Vice President of Treasury and Risk and Chief Risk Officer. The Competitive Risk Committee consists of AEPSC's Chief Financial Officer, Senior Vice President of Treasury and Risk and Chief Risk Officer in addition to Energy Supply's President and Vice President. When commercial activities exceed predetermined limits, positions are modified to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total MTM value as compared to December 31, 2018:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2019

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation & Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2018	$ 90.9	$ (101 0)	$ 164 5	$ 154.4
Gain from Contracts Realized/Settled During the Period and Entered in a Prior Period	(5 4)	(7 2)	(19 2)	(31 8)
Fair Value of New Contracts at Inception When Entered During the Period (a)	—	—	8.3	8.3
Changes in Fair Value Due to Market Fluctuations During the Period (b)	—	—	9.8	9 8
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(9.6)	4 6	—	(5.0)
Total MTM Risk Management Contract Net Assets (Liabilities) as of December 31, 2019	$ 75 9	$ (103 6)	$ 163.4	135.7
Commodity Cash Flow Hedge Contracts				(125.5)
Interest Rate Cash Flow Hedge Contracts				4.6
Fair Value Hedge Contracts				14.5
Collateral Deposits				34 0
Total MTM Derivative Contract Net Assets as of December 31, 2019				$ 63.3

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices The contract prices are valued against market curves associated with the delivery location and delivery term A significant portion of the total volumetric position has been economically hedged
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income These net gains (losses) are recorded as regulatory liabilities/assets or accounts payable

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to risk management contracts. The following tables and discussion provide information on credit risk and market volatility risk.

Credit Risk

Credit risk is mitigated in wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. Management uses credit agency ratings and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

AEP has risk management contracts (includes non-derivative contracts) with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, exposures change daily. As of December 31, 2019, credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2019, the following table approximates AEP's counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 513.4	$ —	$ 513.4	2	$ 208.1
Split Rating	3.1	—	3.1	2	3.1
No External Ratings:					
Internal Investment Grade	135.8	—	135.8	4	82.2
Internal Noninvestment Grade	55.7	10.5	45.2	2	28.6
Total as of December 31, 2019	$ 708.0	$ 10.5	$ 697.5		

All exposure in the table above relates to either AEPSC or AEPEP. In addition, AEP is exposed to credit risk related to participation in RTOs. For each of the RTOs in which AEP participates, this risk is generally determined based on the proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

Management uses a risk measurement model, which calculates VaR, to measure AEP's commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2019, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

Management calculates the VaR for both a trading and non-trading portfolio. The trading portfolio consists primarily of contracts related to energy trading and marketing activities. The non-trading portfolio consists primarily of economic hedges of generation and retail supply activities. The following tables show the end, high, average and low market risk as measured by VaR for the periods indicated:

VaR Model
Trading Portfolio

Twelve Months Ended December 31, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.1	$ 1.2	$ 0.2	$ 0.1	$ 1.1	$ 1.8	$ 0.3	$ 0.1

VaR Model
Non-Trading Portfolio

Twelve Months Ended December 31, 2019				Twelve Months Ended December 31, 2018			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ 0.2	$ 8.5	$ 1.1	$ 0.2	$ 4.0	$ 16.5	$ 2.7	$ 0.4

Management back-tests VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As the VaR calculation captures recent price movements, management also performs regular stress testing of the trading portfolio to understand AEP's exposure to extreme price movements. A historical-based method is employed whereby the current trading portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. Management then researches the underlying positions, price movements and market events that created the most significant exposure and reports the findings to the Risk Executive Committee, Regulated Risk Committee or Competitive Risk Committee as appropriate.

Interest Rate Risk

AEP is exposed to interest rate market fluctuations in the normal course of business operations. AEP has outstanding short and long-term debt which is subject to a variable rate. AEP manages interest rate risk by limiting variable-rate exposures to a percentage of total debt, by entering into interest rate derivative instruments and by monitoring the effects of market changes in interest rates. For the 12 months ended December 31, 2019, 2018 and 2017, a 100 basis point change in the benchmark rate on AEP's variable rate debt would impact pretax interest expense annually by $24 million, $25 million and $28 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2019, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that (i) relate to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Accounting for the Effects of Cost-Based Regulation

As described in Notes 1, 4, and 5 to the consolidated financial statements, the Company's consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. Regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation in the same accounting period by matching expenses with their recovery through regulated revenues and matching income with its passage to customers in cost-based regulated rates. Management reviews the probability of recovery of regulatory assets and refund of regulatory liabilities at each balance sheet date, or whenever new events occur, whether influenced by regulatory commission orders, new legislation, or changes in the regulatory environment. As of December 31, 2019, there were $3.3 billion of deferred costs included in regulatory assets, $o.2 billion of which were pending final regulatory approval, and $8.5 billion of regulatory liabilities awaiting potential refund or future rate reduction, $0.5 billion of which were pending final regulatory determination.

The principal considerations for our determination that performing procedures relating to the accounting for the effects of cost-based regulation is a critical audit matter are there was significant judgment and estimation by management in the ongoing evaluation of the recovery of regulatory assets and refund of regulatory liabilities, and applying guidance contained in rate orders and other relevant evidence. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to management's judgments about the probability of recovery of regulatory assets and refund of regulatory liabilities, including estimates made to record recoveries, refunds and disallowances.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's assessment of regulatory proceedings, including the probability of recovery of regulatory assets and refund of regulatory liabilities, including management's development of the estimates made to record any recoveries, refunds and disallowances. These procedures also included, among others, evaluating the reasonableness of management's assessment of probability of future recovery for regulatory assets and refund of regulatory liabilities, and testing management's process and evaluating the reasonableness of management's estimates of amounts to be refunded or recovered and the time period over which the refunds will be made or the recoveries will occur. Testing of regulatory assets and liabilities, including those subject to pending rate cases, also involved evaluating the provisions and formulas outlined in rate orders, other regulatory correspondence, and application of regulatory precedents.

Valuation of Level 3 Risk Management Commodity Contracts

As described in Notes 1, 10 and 11 to the consolidated financial statements, the Company employs risk management commodity contracts including physical and financial forward purchase-and-sale contracts and, to a lesser extent, over-the-counter swaps and options to accomplish its risk management strategies. Certain over-the-counter and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. The fair value of these risk management commodity contracts is estimated based on available market information using discounted cash flow models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. The main driver of the classification of risk management contracts within Level 3 in the fair value hierarchy is the lack of observable energy price curves in the market, which required management to apply significant judgment in developing its estimate of energy prices in future periods. Management utilized such unobservable pricing data to value its Level 3 risk management commodity contract assets and liabilities, which totaled $372.4 million and $262.5 million, as of December 31, 2019, respectively.

The principal considerations for our determination that performing procedures relating to the valuation of Level 3 risk management commodity contracts is a critical audit matter are there was significant judgment and estimation by management when developing the fair value of the commodity contracts. This in turn led to significant audit effort and a high degree of auditor subjectivity in performing procedures and in evaluating audit evidence relating to the unobservable assumptions used within management's discounted cash flow models, including projections of forward commodity prices, supply and demand levels, and future price volatility. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's valuation of the risk management commodity contracts, including controls over the assumptions used to value the Level 3 risk management commodity contracts. These procedures also included, among others, testing the data used in and management's process for developing the fair value of the Level 3 risk management commodity contracts. Professionals with specialized skill and knowledge were used to assist in evaluating the appropriateness of the discounted cash flow models and reasonableness of the assumptions used by management, including the forward commodity prices, supply and demand levels, and future price volatility.

Acquisition of Sempra Renewables LLC

As described in Notes 7 and 17 to the consolidated financial statements, the Company completed the acquisition of Sempra Renewables LLC for net consideration of $580.4 million in 2019. Management applied significant judgment in estimating the fair value of net assets acquired, which involved the use of significant estimates and assumptions, including the pricing and terms of the existing purchase power agreements, forecasted market power prices, expected wind farm net capacity, and discount rates reflecting risk inherent in the future cash flows and future power prices.

The principal considerations for our determination that performing procedures relating to the acquisition of Sempra Renewables LLC is a critical audit matter are there was significant audit effort and a high degree of auditor subjectivity in performing procedures relating to the fair value measurement of the net assets acquired due to the significant amount of judgment used by management when developing the estimates. Significant audit effort was required in evaluating the significant assumptions relating to the future cash flows, specifically, forecasted market power prices, expected wind farm net capacity, and discount rates. In addition, the audit effort involved the use of professionals with specialized skill and knowledge to assist in performing these procedures and evaluating the audit evidence obtained.

Addressing the matter involved procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to the acquisition accounting, including controls over management's valuation of the acquired net assets and controls over development of the significant estimates and assumptions related to the future cash flows, specifically forecasted market power prices, expected wind farm net generation and discount rates. These procedures also included, among others, reading the purchase agreement and the related power purchase contracts, testing management's process for estimating the fair value of acquired net assets, and evaluating management's future cash flows and discount rates used to estimate the fair value of the acquired net assets, using professionals with specialized skill and knowledge to assist in doing so. Testing management's process included evaluating the appropriateness of the valuation methods and the reasonableness of the future cash flows, specifically market power prices, expected wind farm net capacity, and discount rates. Evaluating the reasonableness of forecasted market power prices involved evaluating the cost of constructing and operating a new wind plant over an assumed life in the same geographic region as of the acquisition date using third party market participant assumptions. Evaluating the reasonableness of expected wind farm net capacity involved evaluation against each wind farm's historical and expected generation. Discount rates were evaluated by considering the cost of capital of comparable businesses and other industry factors.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and Subsidiary Companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP's internal control over financial reporting was effective as of December 31, 2019.

PricewaterhouseCoopers LLP, AEP's independent registered public accounting firm has issued an audit report on the effectiveness of AEP's internal control over financial reporting as of December 31, 2019. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Vertically Integrated Utilities	$ 9,245 7	$ 9,556 7	$ 9,095.1
Transmission and Distribution Utilities	4,319 0	4,552 3	4,328 9
Generation & Marketing	1,721 8	1,818.1	1,771.4
Other Revenues	274 9	268 6	229 5
TOTAL REVENUES	15,561.4	16,195.7	15,424 9
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	1,940.9	2,359.4	2,346 5
Purchased Electricity for Resale	3,165 2	3,427.1	2,965 3
Other Operation	2,743 7	2,979 2	2,525 2
Maintenance	1,213 9	1,247 4	1,145 6
Asset Impairments and Other Related Charges	156.4	70 6	87.1
Gain on Sale of Merchant Generation Assets	—	—	(226 4)
Depreciation and Amortization	2,514.5	2,286.6	1,997 2
Taxes Other Than Income Taxes	1,234 5	1,142 7	1,059.4
TOTAL EXPENSES	12,969 1	13,513 0	11,899.9
OPERATING INCOME	2,592 3	2,682 7	3,525 0
Other Income (Expense):			
Other Income	26 6	18 2	34 6
Allowance for Equity Funds Used During Construction	168.4	132.5	93 7
Non-Service Cost Components of Net Periodic Benefit Cost	120 0	124.5	45 5
Gain on Sale of Equity Investment	—	—	12.4
Interest Expense	(1,072 5)	(984 4)	(895.0)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT) AND EQUITY EARNINGS	1,834 8	1,973 5	2,816.2
Income Tax Expense (Benefit)	(12 9)	115 3	969.7
Equity Earnings of Unconsolidated Subsidiaries	72 1	73.1	82.4
NET INCOME	1,919 8	1,931 3	1,928.9
Net Income (Loss) Attributable to Noncontrolling Interests	(1 3)	7 5	16 3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,921 1	$ 1,923 8	$ 1,912.6
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	493,694,345	492,774,600	491,814,651
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3 89	$ 3 90	$ 3 89
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	495,306,238	493,758,277	492,611,067
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.88	$ 3 90	$ 3 88

See Notes to Financial Statements of Registrants beginning on page 156

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
Net Income	$ 1,919 8	$ 1,931.3	$ 1,928 9
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(21 1), $3 9 and $(1 4) in 2019, 2018 and 2017, Respectively	(79 4)	14 6	(2 6)
Securities Available for Sale, Net of Tax of $0, $0 and $1.9 in 2019, 2018 and 2017, Respectively	—	—	3.5
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(1 5), $(1 4) and $0 6 in 2019, 2018 and 2017, Respectively	(5 6)	(5.3)	1 1
Pension and OPEB Funded Status, Net of Tax of $15 3, $(8.8) and $46 7 in 2019, 2018 and 2017, Respectively	57 7	(33 0)	86 5
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(27 3)	(23.7)	88 5
TOTAL COMPREHENSIVE INCOME	1,892 5	1,907 6	2,017 4
Total Comprehensive Income (Loss) Attributable To Noncontrolling Interests	(1.3)	7.5	16.3
TOTAL OTHER COMPREHENSIVE INCOME ATTIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,893 8	$ 1,900 1	$ 2,001 1

See Notes to Financial Statements of Registrants beginning on page 156.

**AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)**

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2016	512.0	$ 3,328 3	$ 6,332.6	$ 7,892.4	$ (156 3)	$ 23.1	$ 17,420 1
Issuance of Common Stock	0 2	1.1	11.1				12 2
Common Stock Dividends				(1,178 3) (a)		(13.6)	(1,191 9)
Other Changes in Equity			55 0			0.8	55 8
Net Income				1,912 6		16 3	1,928.9
Other Comprehensive Income					88.5		88.5
TOTAL EQUITY – DECEMBER 31, 2017	512 2	3,329 4	6,398 7	8,626 7	(67 8)	26 6	18,313 6
Issuance of Common Stock	1 3	8 0	65 6				73 6
Common Stock Dividends				(1,251.1) (a)		(4.4)	(1,255 5)
Other Changes in Equity			21.8			1.3	23.1
ASU 2018-02 Adoption				14.0	(17 0)		(3 0)
ASU 2016-01 Adoption				11.9	(11 9)		—
Net Income				1,923 8		7 5	1,931.3
Other Comprehensive Loss					(23.7)		(23.7)
TOTAL EQUITY – DECEMBER 31, 2018	513 5	3,337 4	6,486 1	9,325 3	(120 4)	31.0	19,059 4
Issuance of Common Stock	0 9	6 0	59 3				65.3
Common Stock Dividends				(1,345 5) (a)		(4 5)	(1,350 0)
Other Changes in Equity			(9 8) (b)			2.2	(7 6)
Acquisition of Sempra Renewables LLC						134 8	134.8
Acquisition of Santa Rita East						118.8	118 8
Net Income (Loss)				1,921 1		(1 3)	1,919.8
Other Comprehensive Loss					(27.3)		(27 3)
TOTAL EQUITY – DECEMBER 31, 2019	514 4	$ 3,343 4	$ 6,535 6	$ 9,900 9	$ (147 7)	$ 281.0	$ 19,913 2

(a) Cash dividends declared per AEP common share were $2 71, $2 53 and $2 39 for the years ended December 31, 2019, 2018 and 2017, respectively
(b) Includes $(62) million related to a forward equity purchase contract associated with the issuance of Equity Units See "Equity Units" section of Note 14 for additional information

See Notes to Financial Statements of Registrants beginning on page 156

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 246 8	$ 234 1
Restricted Cash (December 31, 2019 and 2018 Amounts Include $185 8 and $210, Respectively, Related to Transition Funding, Restoration Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and Santa Rita East)	185 8	210 0
Other Temporary Investments (December 31, 2019 and 2018 Amounts Include $187 8 and $152 7, Respectively, Related to EIS and Transource Energy)	202 7	159 1
Accounts Receivable		
Customers	625 3	699 0
Accrued Unbilled Revenues	222 4	209 3
Pledged Accounts Receivable – AEP Credit	873 9	999 8
Miscellaneous	27 2	55 2
Allowance for Uncollectible Accounts	(43 7)	(36 8)
Total Accounts Receivable	1,705 1	1,926 5
Fuel	528 5	319 0
Materials and Supplies	640 7	602 1
Risk Management Assets	172 8	162 8
Regulatory Asset for Under-Recovered Fuel Costs	92 9	150 1
Margin Deposits	60 4	141 4
Prepayments and Other Current Assets	242 1	208 8
TOTAL CURRENT ASSETS	4,077 8	4,113 9
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Generation	22,762 4	21,699 9
Transmission	24,808 6	21,531 0
Distribution	22,443 4	21,195 4
Other Property, Plant and Equipment (Including Coal Mining and Nuclear Fuel)	4,811 5	4,265 0
Construction Work in Progress	4,319 8	4,393 9
Total Property, Plant and Equipment	79,145 7	73,085 2
Accumulated Depreciation and Amortization	19,007.6	17,986 1
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	60,138 1	55,099 1
OTHER NONCURRENT ASSETS		
Regulatory Assets	3,158 8	3,310 4
Securitized Assets	858 1	920 6
Spent Nuclear Fuel and Decommissioning Trusts	2,975 7	2,474 9
Goodwill	52 5	52 5
Long-term Risk Management Assets	266 6	254 0
Operating Lease Assets	957 4	—
Deferred Charges and Other Noncurrent Assets	3,407 3	2,577 4
TOTAL OTHER NONCURRENT ASSETS	11,676 4	9,589 8
TOTAL ASSETS	$ 75,892 3	$ 68,802 8

See Notes to Financial Statements of Registrants beginning on page 156

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2019 and 2018
(dollars in millions)

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Accounts Payable	$ 2,085.8	$ 1,874 3
Short-term Debt		
Securitized Debt for Receivables – AEP Credit	710 0	750 0
Other Short-term Debt	2,128 3	1,160 0
Total Short-term Debt	2,838 3	1,910 0
Long-term Debt Due Within One Year (December 31, 2019 and 2018 Amounts Include $565 1 and $406 5, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	1,598 7	1,698 5
Risk Management Liabilities	114 3	55 0
Customer Deposits	366 1	412 2
Accrued Taxes	1,357 8	1,218 0
Accrued Interest	243 6	231 7
Obligations Under Operating Leases	234 1	—
Regulatory Liability for Over-Recovered Fuel Costs	86 6	58 6
Other Current Liabilities	1,373 8	1,190 5
TOTAL CURRENT LIABILITIES	10,299 1	8,648 8
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2019 and 2018 Amounts Include $907 and $1,109 2, Respectively, Related to Transition Funding, DCC Fuel, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding, Transource Energy, Sabine and Restoration Funding)	25,126 8	21,648.2
Long-term Risk Management Liabilities	261 8	263 4
Deferred Income Taxes	7,588 2	7,086 5
Regulatory Liabilities and Deferred Investment Tax Credits	8,457 6	8,540 3
Asset Retirement Obligations	2,216 6	2,287 7
Employee Benefits and Pension Obligations	466 0	377 1
Obligations Under Operating Leases	734 6	—
Deferred Credits and Other Noncurrent Liabilities	719 8	782 6
TOTAL NONCURRENT LIABILITIES	45,571 4	40,985 8
TOTAL LIABILITIES	55,870 5	49,634 6
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEZZANINE EQUITY		
Redeemable Noncontrolling Interest	65 7	69 4
Contingently Redeemable Performance Share Awards	42 9	39 4
TOTAL MEZZANINE EQUITY	108 6	108 8
EQUITY		
Common Stock – Par Value – $6 50 Per Share		

	2019	2018
Shares Authorized	600,000,000	600,000,000
Shares Issued	514,373,631	513,450,036

(20,204,160 Shares were Held in Treasury as of December 31, 2019 and 2018, Respectively)	3,343 4	3,337 4
Paid-in Capital	6,535 6	6,486 1
Retained Earnings	9,900 9	9,325 3

Accumulated Other Comprehensive Income (Loss)	(147 7)	(120.4)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	19,632 2	19,028.4
Noncontrolling Interests	281.0	31 0
TOTAL EQUITY	19,913 2	19,059.4
TOTAL LIABILITIES, MEZZANINE EQUITY AND EQUITY	$ 75,892 3	$ 68,802 8

See Notes to Financial Statements of Registrants beginning on page 156

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
OPERATING ACTIVITIES			
Net Income	$ 1,919 8	$ 1,931 3	$ 1,928 9
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	2,514 5	2,286 6	1,997 2
Rockport Plant, Unit 2 Operating Lease Amortization	136 5	—	—
Deferred Income Taxes	(17 8)	104 3	901 5
Asset Impairments and Other Related Charges	156 4	70 6	87 1
Allowance for Equity Funds Used During Construction	(168 4)	(132 5)	(93 7)
Mark-to-Market of Risk Management Contracts	(29 2)	(66 4)	(23 3)
Amortization of Nuclear Fuel	89.1	113 8	129 1
Pension and Postemployment Benefit Reserves	(24 6)	(42 8)	27 8
Pension Contributions to Qualified Plan Trust	—	—	(93 3)
Property Taxes	(73 8)	(59 1)	(29 5)
Deferred Fuel Over/Under-Recovery, Net	85.2	189 7	84 4
Gain on Sale of Merchant Generation Assets	—	—	(226 4)
Recovery of Ohio Capacity Costs, Net	34 1	67 7	83 2
Refund of Global Settlement	(16 5)	(5 5)	(98 2)
Change in Other Noncurrent Assets	(97 4)	119 8	(423 9)
Change in Other Noncurrent Liabilities	(116 1)	129 0	181 7
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	247 8	145 9	28 5
Fuel, Materials and Supplies	(248 2)	20 7	17 9
Accounts Payable	5 8	36 6	(58 0)
Accrued Taxes, Net	138 9	153 2	91 9
Rockport Plant, Unit 2 Operating Lease Payments	(147 7)	—	—
Other Current Assets	70 7	10 5	(60 7)
Other Current Liabilities	(189 0)	149 8	(181 8)
Net Cash Flows from Operating Activities	4,270 1	5,223 2	4,270 4
INVESTING ACTIVITIES			
Construction Expenditures	(6,051 4)	(6,310 9)	(5,691 3)
Purchases of Investment Securities	(1,576 0)	(2,067 8)	(2,314 7)
Sales of Investment Securities	1,494 2	2,010 0	2,256 3
Acquisitions of Nuclear Fuel	(92 3)	(46 1)	(108 0)
Acquisition of Sempra Renewables LLC and Santa Rita East, net of cash and restricted cash acquired	(918 4)	—	—
Proceeds from Sale of Merchant Generation Assets	—	—	2,159 6
Other Investing Activities	(0 6)	61 2	41 7
Net Cash Flows Used for Investing Activities	(7,144 5)	(6,353 6)	(3,656 4)
FINANCING ACTIVITIES			
Issuance of Common Stock	65 3	73 6	12 2
Issuance of Long-term Debt	4,536 6	4,945 7	3,854 1
Commercial Paper and Credit Facility Borrowings	—	205 6	—
Change in Short-term Debt, Net	928 3	271 4	(74 4)
Retirement of Long-term Debt	(1,220 8)	(2,782 0)	(3,087 9)
Commercial Paper and Credit Facility Repayments	—	(205 6)	—
Make Whole Premium on Extinguishment of Long-term Debt	(5 0)	(13 5)	(46 1)
Principal Payments for Finance Lease Obligations	(70 7)	(65 1)	(67 3)
Dividends Paid on Common Stock	(1,350 0)	(1,255 5)	(1,191 9)

Other Financing Activities		(20.8)		(12.7)		(3 6)
Net Cash Flows from (Used for) Financing Activities		2,862 9		1,161 9		(604 9)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash		(11 5)		31 5		9 1
Cash, Cash Equivalents and Restricted Cash at Beginning of Period		444 1		412 6		403 5
Cash, Cash Equivalents and Restricted Cash at End of Period	$	432 6	$	444 1	$	412 6

See Notes to Financial Statements of Registrants beginning on page 156

AEP TEXAS INC.
AND SUBSIDIARIES

AEP TEXAS INC. AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

AEP Texas was formed by the merger of TCC and TNC into AEP Utilities on December 31, 2016. The merging parties consolidated the majority of their rate structures following the completion of their 2019 base rate case. See Note 4 - Rate Matters for additional information related to the 2019 base rate case. Following the merger, AEP Utilities changed its name to AEP Texas.

AEP Texas is engaged in the transmission and distribution of electric power to approximately 1,049,000 retail customers through REPs in west, central and southern Texas. Among the principal industries served by AEP Texas are petroleum and coal products manufacturing, chemical manufacturing, oil and gas extraction, pipeline transportation and primary metal manufacturing. The territory served by AEP Texas also includes several military installations and correctional facilities. AEP Texas is a member of ERCOT. Under Texas Restructuring Legislation, AEP Texas' utility predecessors, TCC and TNC, exited the generation business and ceased serving retail load. However, AEP Texas continues as part owner in the Oklaunion Power Station operated by PSO, which management announced plans to close by October 2020 pending necessary approvals. AEP Texas consolidates AEP Texas North Generation Company, LLC, AEP Texas Central Transition Funding II LLC, AEP Texas Central Transition Funding III LLC and AEP Texas Restoration Funding LLC, its wholly-owned subsidiaries.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	11,996	12,101	11,569
Commercial	10,419	10,220	10,382
Industrial	8,882	9,053	8,964
Miscellaneous	665	646	638
Total Retail (a)	31,962	32,020	31,553

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2019	2018	2017
	(in degree days)		
Actual – Heating (a)	301	354	239
Normal – Heating (b)	322	325	330
Actual – Cooling (c)	2,989	2,861	2,950
Normal – Cooling (b)	2,699	2,688	2,669

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 70 degree temperature base.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019 Net Income (in millions)

Year Ended December 31, 2018	$	211.3
Changes in Gross Margin:		
Retail Margins		(28.4)
Margins from Off-system Sales		61.0
Transmission Revenues		75.8
Other Revenues		13.0
Total Change in Gross Margin		121.4
Changes in Expenses and Other:		
Other Operation and Maintenance		(72.5)
Asset Impairments and Other Related Charges		(32.5)
Depreciation and Amortization		(122.7)
Taxes Other Than Income Taxes		(8.0)
Interest Income		2.6
Allowance for Equity Funds Used During Construction		(4.8)
Non-Service Cost Components of Net Periodic Benefit Cost		(1.0)
Interest Expense		10.1
Total Change in Expenses and Other		(228.8)
Income Tax Expense (Benefit)		74.4
Year Ended December 31, 2019	$	178.3

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals were as follows:

- **Retail Margins** decreased $28 million primarily due to the following:
  - A $30 million decrease due to a provision for refund in the 2019 Texas Base Rate Case.
  - A $2 million decrease in weather-related usage primarily due to a 15% decrease in heating degree days, partially offset by a 4% increase in cooling degree days.

  These decreases were partially offset by:
  - A $5 million increase in weather-normalized margins primarily in the residential and commercial classes.
- **Margins from Off-system Sales** increased $61 million due to higher affiliated PPA revenues. This increase was partially offset below in Other Operation and Maintenance expenses and in Depreciation and Amortization expenses.
- **Transmission Revenues** increased $76 million primarily due to recovery of increased transmission investment in ERCOT.
- **Other Revenues** increased $13 million primarily due to securitization revenue. This increase was offset below in Depreciation and Amortization expenses and in Interest Expense.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses increased $73 million primarily due to the following:
  - A $64 million increase in expense due to the partial amortization of the Texas Storm Cost Securitization regulatory asset as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019. This increase was offset in Income Tax Expense (Benefit) below.
  - A $6 million increase due to a charitable contribution to the AEP Foundation.
  - A $4 million increase due to a regulatory disallowance in the 2019 Texas Base Rate Case for rate case expenses.

  These increases were partially offset by:
  - A $7 million decrease in ERCOT transmission expenses. This decrease was partially offset in Retail Margins above.
  - A $3 million decrease in expenses associated with Oklaunion Power Station. This decrease was partially offset in Margins from Off-system Sales above and in Depreciation and Amortization expenses below.
- **Asset Impairments and Other Related Charges** increased $33 million due to regulatory disallowances in the 2019 Texas Base Rate Case.
- **Depreciation and Amortization** expenses increased $123 million primarily due to the following:
  - A $49 million increase in depreciation expense due to a change in the useful life of the Oklaunion Power Station. This increase was partially offset above in Margins from Off-system Sales and in Other Operation and Maintenance expenses.
  - A $47 million increase in depreciation expense due to an increase in the depreciable base of transmission and distribution assets primarily related to advanced metering systems.
  - A $20 million increase in securitization amortizations. This increase was offset in Other Revenues above and in Interest Expense below.
  - A $6 million increase in ARO associated with Oklaunion Power Station.
- **Taxes Other Than Income Taxes** increased $8 million primarily due to an increase in property taxes driven by additional investments in transmission and distribution assets.
- **Allowance for Equity Funds Used During Construction** decreased $5 million primarily due to a decrease in the Equity component as a result of higher short-term debt balances, partially offset by increased transmission projects.
- **Interest Expense** decreased $10 million primarily due to the following:
  - A $21 million decrease due to the deferral of previously recorded interest expense approved for recovery as a result of the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019.
  - A $10 million decrease in expense related to securitization assets. This decrease was offset above in Other Revenues and Depreciation and Amortization expenses.

  These decreases were partially offset by:
  - A $16 million increase due to higher long-term debt balances.
  - A $3 million increase due to higher short-term debt balances.
- **Income Tax Expense (Benefit)** decreased $74 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements as approved in the Texas Storm Cost Securitization financing order issued by the PUCT in June 2019 and a decrease in pretax book income. This decrease was partially offset above in Other Operation and Maintenance expenses.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
AEP Texas Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Texas Inc. and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Texas Inc. and Subsidiaries (AEP Texas) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP Texas' internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP Texas' internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEP Texas' internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEP Texas' registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEP Texas to provide only management's report in this annual report.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Transmission and Distribution	$ 1,545 9	$ 1,486 3	$ 1,470.3
Sales to AEP Affiliates	160 5	105.2	65 7
Other Revenues	2 9	3 8	2 4
TOTAL REVENUES	1,709 3	1,595.3	1,538 4
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	31.1	38 5	20.9
Other Operation	492 0	488.9	453 1
Maintenance	158 8	89 4	75.9
Asset Impairments and Other Related Charges	32 5	—	—
Depreciation and Amortization	622 3	499.6	450.1
Taxes Other Than Income Taxes	140 6	132 6	122.3
TOTAL EXPENSES	1,477 3	1,249 0	1,122 3
OPERATING INCOME	232 0	346 3	416 1
Other Income (Expense):			
Interest Income	3 4	0 8	2 9
Allowance for Equity Funds Used During Construction	15.2	20 0	6.8
Non-Service Cost Components of Net Periodic Benefit Cost	11 3	12 3	3 6
Interest Expense	(137 2)	(147.3)	(142.3)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	124 7	232.1	287 1
Income Tax Expense (Benefit)	(53 6)	20.8	(23 4)
NET INCOME	$ 178 3	$ 211 3	$ 310.5

The common stock of AEP Texas is wholly-owned by Parent

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
Net Income	$ 178 3	$ 211 3	$ 310 5
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $0 3, $0 3 and $0 5 in 2019, 2018 and 2017, Respectively	1 0	1 0	0.9
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $0, $0 1 and $0 1 in 2019, 2018 and 2017, Respectively	0 2	0.2	0.3
Pension and OPEB Funded Status, Net of Tax of $0 3, $(0 3) and $0 6 in 2019, 2018 and 2017, Respectively	1 1	(1 0)	1.1
TOTAL OTHER COMPREHENSIVE INCOME	2.3	0 2	2.3
TOTAL COMPREHENSIVE INCOME	$ 180 6	$ 211 5	$ 312 8

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 857 9	$ 814.1	$ (14.9)	$ 1,657 1
Capital Contribution from Parent	200 0			200 0
Net Income		310 5		310 5
Other Comprehensive Income			2 3	2 3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	1,057 9	1,124 6	(12 6)	2,169 9
Capital Contribution from Parent	200 0			200 0
ASU 2018-02 Adoption		1.8	(2 7)	(0 9)
Net Income		211.3		211 3
Other Comprehensive Income			0 2	0 2
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	1,257 9	1,337 7	(15 1)	2,580 5
Capital Contribution from Parent	200 0			200 0
Net Income		178.3		178 3
Other Comprehensive Income			2 3	2 3
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 1,457 9	$ 1,516 0	$ (12 8)	$ 2,961 1

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3 1	$ 3 1
Restricted Cash (December 31, 2019 and 2018 Amounts Include $154 7 and $156 7, Respectively, Related to Transition Funding and Restoration Funding)	154.7	156 7
Advances to Affiliates	207 2	8 0
Accounts Receivable:		
Customers	116 0	110 9
Affiliated Companies	10 1	15 0
Accrued Unbilled Revenues	68.8	70.4
Miscellaneous	0 3	1 9
Allowance for Uncollectible Accounts	(1 8)	(1.3)
Total Accounts Receivable	193 4	196 9
Fuel	5.9	8.8
Materials and Supplies	56 7	52.8
Accrued Tax Benefits	66.1	44.9
Prepayments and Other Current Assets	5.8	5 3
TOTAL CURRENT ASSETS	692 9	476 5
PROPERTY, PLANT AND EQUIPMENT		
Electric		
Generation	351.7	352.1
Transmission	4,466 5	3,683 6
Distribution	4,215 2	4,043 2
Other Property, Plant and Equipment	805 9	727.9
Construction Work in Progress	763 9	836.2
Total Property, Plant and Equipment	10,603 2	9,643 0
Accumulated Depreciation and Amortization	1,758 1	1,651 2
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	8,845 1	7,991.8
OTHER NONCURRENT ASSETS		
Regulatory Assets	280.6	430 0
Securitized Assets (December 31, 2019 and 2018 Amounts Include $621 2 and $636 8, Respectively, Related to Transition Funding and Restoration Funding)	623 4	649.1
Deferred Charges and Other Noncurrent Assets	147 1	56.3
TOTAL OTHER NONCURRENT ASSETS	1,051.1	1,135 4
TOTAL ASSETS	$ 10,589.1	$ 9,603.7

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018
(in millions)

	December 31,	
	2019	**2018**
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 216 0
Accounts Payable		
General	256.8	276.5
Affiliated Companies	35 6	30 3
Long-term Debt Due Within One Year – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $281 4 and $251.1, Respectively, Related to Transition Funding and Restoration Funding)	392 1	501 1
Risk Management Liabilities	—	0 2
Accrued Taxes	84.9	75.5
Accrued Interest (December 31, 2019 and 2018 Amounts Include $7 5 and $11 3, Respectively, Related to Transition Funding and Restoration Funding)	35 7	37.3
Oklaunion Purchase Power Agreement	22 1	24.3
Obligations Under Operating Leases	12 0	—
Other Current Liabilities	188 0	98.3
TOTAL CURRENT LIABILITIES	1,027.2	1,259.5
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated (December 31, 2019 and 2018 Amounts Include $495 4 and $540.1, Respectively, Related to Transition Funding and Restoration Funding)	4,166.3	3,380 2
Deferred Income Taxes	965 4	913 1
Regulatory Liabilities and Deferred Investment Tax Credits	1,316 9	1,344 3
Oklaunion Purchase Power Agreement	—	22 1
Obligations Under Operating Leases	71.1	—
Deferred Credits and Other Noncurrent Liabilities	81 1	104 0
TOTAL NONCURRENT LIABILITIES	6,600 8	5,763 7
TOTAL LIABILITIES	7,628 0	7,023 2
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Paid-in Capital	1,457 9	1,257.9
Retained Earnings	1,516 0	1,337 7
Accumulated Other Comprehensive Income (Loss)	(12 8)	(15 1)
TOTAL COMMON SHAREHOLDER'S EQUITY	2,961 1	2,580.5
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 10,589 1	$ 9,603 7

See Notes to Financial Statements of Registrants beginning on page 156

AEP TEXAS INC. AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 178 3	$ 211.3	$ 310 5
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	622 3	499.6	450.1
Deferred Income Taxes	(23.5)	(16.5)	63.3
Asset Impairments and Other Related Charges	32 5	—	—
Allowance for Equity Funds Used During Construction	(15.2)	(20 0)	(6 8)
Mark-to-Market of Risk Management Contracts	(0 2)	0 7	(0 3)
Pension Contributions to Qualified Plan Trust	—	—	(8 8)
Change in Regulatory Asset – Catastrophe Reserve	44.0	(24.9)	(99.2)
Change in Other Noncurrent Assets	(34.7)	(35 4)	(49.4)
Change in Other Noncurrent Liabilities	11 3	44 9	8 8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	3 5	(2 9)	(23 5)
Fuel, Materials and Supplies	(1 0)	(6.0)	3 2
Accounts Payable	7 5	(20 3)	30.8
Accrued Taxes, Net	(11 8)	(5 6)	(31 3)
Other Current Assets	(0 4)	0 8	0.6
Other Current Liabilities	10 8	26 2	(15.3)
Net Cash Flows from Operating Activities	823.4	651.9	632.7
INVESTING ACTIVITIES			
Construction Expenditures	(1,275 1)	(1,428 8)	(990 9)
Change in Advances to Affiliates, Net	(199.2)	103 9	(103 3)
Other Investing Activities	2 1	35 2	18.9
Net Cash Flows Used for Investing Activities	(1,472.2)	(1,289 7)	(1,075 3)
FINANCING ACTIVITIES			
Capital Contribution from Parent	200 0	200 0	200.0
Issuance of Long-term Debt – Nonaffiliated	1,070 4	494.0	749 6
Change in Advances from Affiliates, Net	(216 0)	216.0	(169 5)
Retirement of Long-term Debt – Nonaffiliated	(401.8)	(266.1)	(323.1)
Principal Payments for Finance Lease Obligations	(5 1)	(4 7)	(3.9)
Other Financing Activities	(0 7)	1 2	(0 2)
Net Cash Flows from Financing Activities	646 8	640 4	452 9
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(2.0)	2 6	10 3
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	159 8	157 2	146.9
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 157 8	$ 159 8	$ 157 2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 148 6	$ 145 9	$ 134.6
Net Cash Paid (Received) for Income Taxes	(11 0)	7 9	(28 3)
Noncash Acquisitions Under Finance Leases	11 4	10.6	8 2
Construction Expenditures Included in Current Liabilities as of December 31,	225 5	243 1	325.7

See Notes to Financial Statements of Registrants beginning on page 156

**AEP TRANSMISSION COMPANY, LLC
AND SUBSIDIARIES**

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

AEPTCo is a holding company for seven FERC regulated transmission-only electric utilities. AEPTCo is an indirect wholly-owned subsidiary of American Electric Power Company, Inc. ("AEP").

AEPTCo's seven wholly-owned public utility companies are (collectively referred to herein as the "State Transcos"):

- AEP Appalachian Transmission Company, Inc. ("APTCo")
- AEP Indiana Michigan Transmission Company, Inc. ("IMTCo")
- AEP Kentucky Transmission Company, Inc. ("KTCo")
- AEP Ohio Transmission Company, Inc. ("OHTCo")
- AEP West Virginia Transmission Company, Inc. ("WVTCo")
- AEP Oklahoma Transmission Company, Inc. ("OKTCo")
- AEP Southwestern Transmission Company, Inc. ("SWTCo")

AEPTCo's business activities are the development, construction and operation of transmission facilities through investments in seven wholly-owned FERC-regulated transmission only electric subsidiaries.

RESULTS OF OPERATIONS

Summary of Investment in Transmission Assets for AEPTCo

	As of December 31,		
	2019	2018	2017
		(in millions)	
Plant In Service	$ 8,407.5	$ 6,689 8	$ 5,446 5
CWIP	1,485 7	1,578 3	1,324 0
Accumulated Depreciation	402 3	271 9	152 6
Total Transmission Property, Net	$ 9,490 9	$ 7,996 2	$ 6,617 9

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$ 315 9
Changes in Transmission Revenues:	
Transmission Revenues	245 3
Total Change in Transmission Revenues	245.3
Changes in Expenses and Other:	
Other Operation and Maintenance	(15 0)
Depreciation and Amortization	(42.1)
Taxes Other Than Income Taxes	(31 1)
Interest Income - Affiliated	0.5
Allowance for Equity Funds Used During Construction	13 7
Interest Expense	(14 2)
Total Change in Expenses and Other	(88 2)
Income Tax Expense	(33 3)
Year Ended December 31, 2019	$ 439 7

The major components of the increase in transmission revenues, which consists of wholesale sales to affiliates and nonaffiliates were as follows.

- **Transmission Revenues** increased $245 million primarily due to continued investment in transmission assets.

Expenses and Other and Income Tax Expense changed between years as follows

- **Other Operation and Maintenance** expenses increased $15 million primarily due to the following:
  - An $8 million increase due to continued investment in transmission assets.
  - A $7 million increase due to a charitable contribution to the AEP Foundation.
- **Depreciation and Amortization** expenses increased $42 million primarily due to a higher depreciable base.
- **Taxes Other Than Income Taxes** increased $31 million primarily due to higher property taxes as a result of increased transmission investment.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to the following:
  - A $15 million increase due to higher monthly CWIP balances.
  - A $12 million increase due to the FERC's approval of a settlement agreement

  These increases were partially offset by.
  - A $13 million decrease due to recent FERC audit findings
- **Interest Expense** increased $14 million primarily due to higher long-term debt balances
- **Income Tax Expense** increased $33 million primarily due to higher pretax book income

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Member of
AEP Transmission Company, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of AEP Transmission Company, LLC and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of changes in member's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of AEP Transmission Company, LLC and Subsidiaries (AEPTCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEPTCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEPTCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded AEPTCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, AEPTCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit AEPTCo to provide only management's report in this annual report.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	**2018**	**2017**
REVENUES			
Transmission Revenues	$ 214 6	$ 177.0	$ 138 0
Sales to AEP Affiliates	806 7	598.9	568 1
Other Revenues	0.1	0.2	0 8
TOTAL REVENUES	1,021 4	776 1	706 9
EXPENSES			
Other Operation	93.9	83.8	60.1
Maintenance	15 4	10.5	8 5
Depreciation and Amortization	176.0	133.9	95.7
Taxes Other Than Income Taxes	168 9	137 8	109 7
TOTAL EXPENSES	454 2	366.0	274.0
OPERATING INCOME	567 2	410.1	432.9
Other Income (Expense):			
Interest Income - Affiliated	3 0	2.5	1.2
Allowance for Equity Funds Used During Construction	84 3	70 6	49 0
Interest Expense	(97 4)	(83.2)	(70 2)
INCOME BEFORE INCOME TAX EXPENSE	557 1	400.0	412 9
Income Tax Expense	117 4	84.1	142 2
NET INCOME	$ 439 7	$ 315 9	$ 270 7

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN MEMBER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Paid-in Capital	Retained Earnings	Total Member's Equity
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2016	$ 1,455 0	$ 502 6	$ 1,957 6
Capital Contribution from Member	361 6		361 6
Net Income		270 7	270 7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2017	1,816.6	773 3	2,589 9
Capital Contribution from Member	664.0		664.0
Net Income		315 9	315 9
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2018	2,480.6	1,089.2	3,569 8
Net Income		439 7	439.7
TOTAL MEMBER'S EQUITY – DECEMBER 31, 2019	$ 2,480 6	$ 1,528 9	$ 4,009 5

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Advances to Affiliates	$ 85.4	$ 96.9
Accounts Receivable:		
Customers	19 0	11.8
Affiliated Companies	66 1	61 0
Total Accounts Receivable	85.1	72 8
Materials and Supplies	13.8	19 0
Accrued Tax Benefits	9 3	33.4
Prepayments and Other Current Assets	3.8	3 4
TOTAL CURRENT ASSETS	197 4	225 5
TRANSMISSION PROPERTY		
Transmission Property	8,137.9	6,515 8
Other Property, Plant and Equipment	269.6	174.0
Construction Work in Progress	1,485.7	1,578.3
Total Transmission Property	9,893.2	8,268 1
Accumulated Depreciation and Amortization	402.3	271.9
TOTAL TRANSMISSION PROPERTY – NET	9,490.9	7,996.2
OTHER NONCURRENT ASSETS		
Regulatory Assets	4.2	12 9
Deferred Property Taxes	193.5	157 9
Deferred Charges and Other Noncurrent Assets	4 8	1.6
TOTAL OTHER NONCURRENT ASSETS	202 5	172.4
TOTAL ASSETS	$ 9,890.8	$ 8,394.1

See Notes to Financial Statements of Registrants beginning on page 156.

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND MEMBER'S EQUITY
December 31, 2019 and 2018

	December 31, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 137 0	$ 45.4
Accounts Payable		
General	493 4	347.2
Affiliated Companies	71 2	56 0
Long-term Debt Due Within One Year – Nonaffiliated	—	85.0
Accrued Taxes	355 6	288.9
Accrued Interest	19 2	15.9
Obligations Under Operating Leases	2.1	—
Other Current Liabilities	14 6	3 8
TOTAL CURRENT LIABILITIES	1,093 1	842 2
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	3,427 3	2,738.0
Deferred Income Taxes	817 8	704 4
Regulatory Liabilities	540 9	521 3
Obligations Under Operating Leases	1 9	—
Deferred Credits and Other Noncurrent Liabilities	0 3	18.4
TOTAL NONCURRENT LIABILITIES	4,788 2	3,982.1
TOTAL LIABILITIES	5,881.3	4,824 3
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
MEMBER'S EQUITY		
Paid-in Capital	2,480 6	2,480 6
Retained Earnings	1,528.9	1,089.2
TOTAL MEMBER'S EQUITY	4,009 5	3,569 8
TOTAL LIABILITIES AND MEMBER'S EQUITY	$ 9,890 8	$ 8,394 1

See Notes to Financial Statements of Registrants beginning on page 156

AEP TRANSMISSION COMPANY, LLC AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 439.7	$ 315.9	$ 270.7
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	176.0	133.9	95.7
Deferred Income Taxes	91.3	98.9	271.5
Allowance for Equity Funds Used During Construction	(84.3)	(70.6)	(49.0)
Property Taxes	(35.6)	(32.9)	(22.8)
Change in Other Noncurrent Assets	9.6	14.6	11.0
Change in Other Noncurrent Liabilities	(8.1)	17.4	27.5
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(5.4)	36.7	(30.4)
Materials and Supplies	5.2	(5.4)	(8.6)
Accounts Payable	37.6	(7.5)	23.0
Accrued Taxes, Net	90.8	73.4	16.3
Accrued Interest	3.3	0.9	4.5
Other Current Assets	(0.3)	(0.3)	(4.8)
Other Current Liabilities	(11.2)	(26.4)	0.2
Net Cash Flows from Operating Activities	708.6	548.6	604.8
INVESTING ACTIVITIES			
Construction Expenditures	(1,410.1)	(1,526.4)	(1,513.4)
Change in Advances to Affiliates, Net	11.5	49.4	(79.2)
Acquisitions of Assets	(9.4)	(37.4)	(9.1)
Other Investing Activities	4.8	1.1	6.1
Net Cash Flows Used for Investing Activities	(1,403.2)	(1,513.3)	(1,595.6)
FINANCING ACTIVITIES			
Capital Contributions from Member	—	664.0	361.6
Issuance of Long-term Debt – Nonaffiliated	688.0	321.0	617.6
Change in Advances from Affiliates, Net	91.6	29.7	11.6
Retirement of Long-term Debt – Nonaffiliated	(85.0)	(50.0)	—
Net Cash Flows from Financing Activities	694.6	964.7	990.8
Net Change in Cash and Cash Equivalents	—	—	—
Cash and Cash Equivalents at Beginning of Period	—	—	—
Cash and Cash Equivalents at End of Period	$ —	$ —	$ —
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 90.6	$ 80.2	$ 62.4
Net Cash Paid (Received) for Income Taxes	1.5	(30.7)	(107.3)
Noncash Acquisitions Under Finance Leases	—	—	0.2
Construction Expenditures Included in Current Liabilities as of December 31,	472.7	345.0	485.0

See Notes to Financial Statements of Registrants beginning on page 156

APPALACHIAN POWER COMPANY
AND SUBSIDIARIES

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, APCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 956,000 retail customers in its service territory in southwestern Virginia and southern West Virginia. APCo consolidates Cedar Coal Company, Central Appalachian Coal Company, Southern Appalachian Coal Company and Appalachian Consumer Rate Relief Funding LLC, its wholly-owned subsidiaries. APCo sells power at wholesale to municipalities. APCo shares its off-system sales margins with its Virginia customers. APCo's off-system sales margins are returned to APCo's West Virginia customers through the ENEC clause.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. APCo shares in the revenues and expenses associated with these risk management activities with the member companies.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including APCo, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

APCo is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31, 2019	2018	2017
	(in millions of KWhs)		
Retail:			
Residential	11,253	11,871	10,701
Commercial	6,365	6,581	6,434
Industrial	9,546	9,576	9,622
Miscellaneous	857	866	836
Total Retail (a)	28,021	28,894	27,593
Wholesale	3,085	2,693	3,089
Total KWhs	31,106	31,587	30,682

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31, 2019	2018	2017
	(in degree days)		
Actual – Heating (a)	2,057	2,400	1,848
Normal – Heating (b)	2,224	2,230	2,235
Actual – Cooling (c)	1,597	1,587	1,249
Normal – Cooling (b)	1,221	1,208	1,201

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	367.8
Changes in Gross Margin:		
Retail Margins		12.2
Margins from Off-system Sales		1.9
Transmission Revenues		34.3
Other Revenues		2.7
Total Change in Gross Margin		51.1
Changes in Expenses and Other:		
Other Operation and Maintenance		5.5
Asset Impairment and Other Related Charges		(92.9)
Depreciation and Amortization		(38.4)
Taxes Other Than Income Taxes		(11.5)
Interest Income		0.6
Carrying Costs Income		(1.3)
Allowance for Equity Funds Used During Construction		3.4
Non-Service Cost Components of Net Periodic Benefit Cost		(0.9)
Interest Expense		(10.2)
Total Change in Expenses and Other		(145.7)
Income Tax Expense (Benefit)		33.1
Year Ended December 31, 2019	$	306.3

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $12 million primarily due to the following:
  - A $78 million increase due to a 2018 reduction in the deferred fuel under-recovery balance as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $30 million increase in deferred fuel related to recoverable PJM expenses that were offset below.
  - A $23 million increase primarily due to revenue from rate riders in West Virginia. This increase was offset in other expense items below.
  - An $18 million increase due to base rate increases in West Virginia implemented in March 2019.
  - A $10 million increase due to 2018 Virginia legislation which increased non-recoverable fuel expense in the prior year.

  These increases were partially offset by:
  - A $95 million decrease due to customer refunds related to Tax Reform. This decrease was partially offset in Income Tax Expense (Benefit) below.
  - A $38 million decrease in weather-related usage primarily driven by a 14% decrease in heating degree days.
  - A $14 million decrease in weather-normalized margins occurring across all retail classes.
- **Transmission Revenues** increased $34 million primarily due to the following:
  - An $18 million increase due to an increase in the net revenue requirement.
  - A $16 million increase due to 2018 provisions for refunds.

Expenses and Other and Income Tax Expense (Benefit) changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $6 million primarily due to the following:
  - A $39 million decrease due to the extinguishment of certain regulatory asset balances as agreed to within the 2018 West Virginia Tax Reform settlement. This decrease was partially offset in Retail Margins above and Income Tax Expense (Benefit) below.
  - A $14 million decrease in maintenance expense at various generation plants.
  - An $11 million decrease in storm-related expenses.
  - A $10 million decrease in expense due to lower current year amortization of certain regulatory assets that were extinguished in August 2018 as agreed to within the 2018 West Virginia Tax Reform settlement.
  - A $6 million decrease in estimated expenses for claims related to asbestos exposure.
  - A $5 million decrease in vegetation management services.

  These decreases were partially offset by:
  - A $41 million increase in recoverable PJM transmission expenses. This increase was partially offset within Retail Margins above.
  - A $17 million increase in PJM expenses primarily related to the annual formula rate true-up.
  - A $13 million increase due to 2019 contributions to benefit low income West Virginia residential customers as a result of the 2018 West Virginia Tax Reform settlement. This increase was offset in Income Tax Expense (Benefit) below.
  - A $9 million increase due to a charitable contribution to the AEP Foundation.
- **Asset Impairments and Other Related Charges** increased $93 million due to a pretax expense recorded in 2019 related to previously retired coal-fired assets.
- **Depreciation and Amortization** expenses increased $38 million primarily due to a higher depreciable base and an increase in West Virginia depreciation rates beginning in March 2019.
- **Taxes Other Than Income Taxes** increased $12 million primarily due to the following:
  - A $9 million increase in West Virginia business and occupational taxes.
  - A $3 million increase in property taxes due to additional investments in utility plant.
- **Allowance for Equity Funds Used During Construction** increased $3 million due to an increase in construction activity.
- **Interest Expense** increased $10 million primarily due to higher long-term debt balances.
- **Income Tax Expense (Benefit)** decreased $33 million primarily due to an increase in amortization of Excess ADIT not subject to normalization requirements and a decrease in pretax book income. This decrease was partially offset in Gross Margin and Other Operation and Maintenance expenses above.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Appalachian Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Appalachian Power Company and its subsidiaries (the "Company") as of December 31, 2019 and 2018, and the related consolidated statements of income, of comprehensive income (loss), of changes in common shareholder's equity and of cash flows for each of the three years in the period ended December 31, 2019, including the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2019 in conformity with accounting principles generally accepted in the United States of America.

Change in Accounting Principle

As discussed in Note 13 to the consolidated financial statements, the Company changed the manner in which it accounts for leases in 2019.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Columbus, Ohio
February 20, 2020

We have served as the Company's auditor since 2017.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Appalachian Power Company and Subsidiaries (APCo) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. APCo's internal control is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of APCo's internal control over financial reporting as of December 31, 2019. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework (2013). Based on management's assessment, management concluded APCo's internal control over financial reporting was effective as of December 31, 2019.

This annual report does not include an audit report from PricewaterhouseCoopers LLP, APCo's registered public accounting firm regarding internal control over financial reporting pursuant to the Securities and Exchange Commission rules that permit APCo to provide only management's report in this annual report.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
REVENUES			
Electric Generation, Transmission and Distribution	$ 2,708.2	$ 2,777.1	$ 2,749.0
Sales to AEP Affiliates	205.3	181.4	172.0
Other Revenues	11.2	9.0	13.2
TOTAL REVENUES	2,924.7	2,967.5	2,934.2
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	607.5	588.9	597.3
Purchased Electricity for Resale	391.0	503.5	357.6
Other Operation	567.6	511.6	503.1
Maintenance	255.4	316.9	251.6
Asset Impairments and Other Related Charges	92.9	—	—
Depreciation and Amortization	466.8	428.4	407.9
Taxes Other Than Income Taxes	146.2	134.7	126.4
TOTAL EXPENSES	2,527.4	2,484.0	2,243.9
OPERATING INCOME	397.3	483.5	690.3
Other Income (Expense):			
Interest Income	2.4	1.8	1.4
Carrying Costs Income	—	1.3	1.4
Allowance for Equity Funds Used During Construction	16.6	13.2	9.2
Non-Service Cost Components of Net Periodic Benefit Cost	17.0	17.9	5.2
Interest Expense	(205.0)	(194.8)	(190.9)
INCOME BEFORE INCOME TAX EXPENSE (BENEFIT)	228.3	322.9	516.6
Income Tax Expense (Benefit)	(78.0)	(44.9)	185.3
NET INCOME	$ 306.3	$ 367.8	$ 331.3

The common stock of APCo is wholly-owned by Parent.

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31, 2019	2018	2017
Net Income	$ 306 3	$ 367 8	$ 331.3
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $(0 2), $(0.2) and $(0 4) in 2019, 2018 and 2017, Respectively	(0 9)	(0 9)	(0 7)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $(0.7), $(0.8) and $(0.6) in 2019, 2018 and 2017, Respectively	(2.5)	(3 1)	(1 2)
Pension and OPEB Funded Status, Net of Tax of $3 6, $(0.7) and $6 3 in 2019, 2018 and 2017, Respectively	13 4	(2 6)	11.6
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	10 0	(6.6)	9.7
TOTAL COMPREHENSIVE INCOME	$ 316 3	$ 361 2	$ 341 0

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2016	$ 260.4	$ 1,828 7	$ 1,502 8	$ (8.4)	$ 3,583.5
Common Stock Dividends			(120.0)		(120.0)
Net Income			331 3		331 3
Other Comprehensive Income				9 7	9 7
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2017	260 4	1,828.7	1,714.1	1.3	3,804 5
Common Stock Dividends			(160 0)		(160.0)
ASU 2018-02 Adoption			0.1	0 3	0.4
Net Income			367 8		367 8
Other Comprehensive Loss				(6 6)	(6.6)
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2018	260 4	1,828 7	1,922 0	(5 0)	4,006 1
Common Stock Dividends			(150 0)		(150 0)
Net Income			306 3		306.3
Other Comprehensive Income				10.0	10 0
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2019	$ 260 4	$ 1,828 7	$ 2,078 3	$ 5.0	$ 4,172.4

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2019 and 2018
(in millions)

	December 31, 2019	December 31, 2018
CURRENT ASSETS		
Cash and Cash Equivalents	$ 3.3	$ 4 2
Restricted Cash for Securitized Funding	23 5	25 6
Advances to Affiliates	22 1	23.0
Accounts Receivable		
Customers	129 0	146.5
Affiliated Companies	64.3	73 4
Accrued Unbilled Revenues	59 7	63.5
Miscellaneous	0 5	2.3
Allowance for Uncollectible Accounts	(2.6)	(2 3)
Total Accounts Receivable	250 9	283.4
Fuel	149 7	61.3
Materials and Supplies	105.2	100 1
Risk Management Assets	39.4	57 2
Regulatory Asset for Under-Recovered Fuel Costs	42 5	99.6
Prepayments and Other Current Assets	64.0	44.3
TOTAL CURRENT ASSETS	700 6	698.7
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	6,563 7	6,509 6
Transmission	3,584.1	3,317.7
Distribution	4,201.7	3,989 4
Other Property, Plant and Equipment	571.3	485 8
Construction Work in Progress	593 4	490 2
Total Property, Plant and Equipment	15,514.2	14,792 7
Accumulated Depreciation and Amortization	4,432 3	4,124.4
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	11,081.9	10,668 3
OTHER NONCURRENT ASSETS		
Regulatory Assets	457 2	475.8
Securitized Assets	234.7	258.7
Long-term Risk Management Assets	0 1	0.9
Operating Lease Assets	78 5	—
Deferred Charges and Other Noncurrent Assets	215.3	188 1
TOTAL OTHER NONCURRENT ASSETS	985 8	923 5
TOTAL ASSETS	$ 12,768 3	$ 12,290 5

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2019 and 2018

	December 31, 2019	December 31, 2018
	(in millions)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 236 7	$ 205 6
Accounts Payable		
General	307.8	263 8
Affiliated Companies	92.5	84.0
Long-term Debt Due Within One Year - Nonaffiliated	215 6	430.7
Risk Management Liabilities	1 9	0.4
Customer Deposits	85 8	88.4
Accrued Taxes	99.6	89 3
Obligations Under Operating Leases	15.2	—
Other Current Liabilities	170 9	191 8
TOTAL CURRENT LIABILITIES	1,226 0	1,354.0
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	4,148 2	3,631 9
Long-term Risk Management Liabilities	—	0.2
Deferred Income Taxes	1,680 8	1,625 8
Regulatory Liabilities and Deferred Investment Tax Credits	1,268 7	1,449 7
Asset Retirement Obligations	102 1	107 1
Employee Benefits and Pension Obligations	50 9	57 1
Obligations Under Operating Leases	64 0	—
Deferred Credits and Other Noncurrent Liabilities	55 2	58 6
TOTAL NONCURRENT LIABILITIES	7,369 9	6,930 4
TOTAL LIABILITIES	8,595 9	8,284.4
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – No Par Value		
Authorized – 30,000,000 Shares		
Outstanding – 13,499,500 Shares	260 4	260 4
Paid-in Capital	1,828 7	1,828 7
Retained Earnings	2,078 3	1,922.0
Accumulated Other Comprehensive Income (Loss)	5 0	(5.0)
TOTAL COMMON SHAREHOLDER'S EQUITY	4,172 4	4,006 1
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 12,768 3	$ 12,290 5

See Notes to Financial Statements of Registrants beginning on page 156.

APPALACHIAN POWER COMPANY AND SUBSIDIARIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2019, 2018 and 2017
(in millions)

	Years Ended December 31,		
	2019	2018	2017
OPERATING ACTIVITIES			
Net Income	$ 306 3	$ 367 8	$ 331.3
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	466 8	428 4	407 9
Deferred Income Taxes	(126 2)	(16 8)	171 5
Asset Impairments and Other Related Charges	92 9	—	—
Allowance for Equity Funds Used During Construction	(16 6)	(13 2)	(9 2)
Mark-to-Market of Risk Management Contracts	19 9	(33 0)	(23.1)
Pension Contributions to Qualified Plan Trust	—	—	(10 2)
Deferred Fuel Over/Under-Recovery, Net	57 1	(10 8)	(20 5)
Change in Other Noncurrent Assets	(38 2)	58 1	11 4
Change in Other Noncurrent Liabilities	(40 3)	(4 8)	11 9
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	35 7	33 6	(28 0)
Fuel, Materials and Supplies	(93 4)	27 8	22 3
Accounts Payable	37 7	(13.3)	37 5
Accrued Taxes, Net	(10 2)	(13 2)	(12 7)
Other Current Assets	15 4	(6 1)	0 7
Other Current Liabilities	(45 5)	42 1	(10 8)
Net Cash Flows from Operating Activities	661 4	846 6	880 0
INVESTING ACTIVITIES			
Construction Expenditures	(862 6)	(780 7)	(818 1)
Change in Advances to Affiliates, Net	0 9	0 5	0 6
Other Investing Activities	24 3	10 8	15 2
Net Cash Flows Used for Investing Activities	(837 4)	(769 4)	(802 3)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	478 2	203 2	320 9
Change in Advances from Affiliates, Net	31 1	19 6	106 4
Retirement of Long-term Debt – Nonaffiliated	(180 5)	(124 0)	(377 9)
Principal Payments for Finance Lease Obligations	(6 7)	(6 9)	(6 9)
Dividends Paid on Common Stock	(150 0)	(160 0)	(120 0)
Other Financing Activities	0 9	1 5	0 5
Net Cash Flows from (Used for) Financing Activities	173 0	(66 6)	(77 0)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash for Securitized Funding	(3 0)	10 6	0 7
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at Beginning of Period	29 8	19 2	18 5
Cash, Cash Equivalents and Restricted Cash for Securitized Funding at End of Period	$ 26 8	$ 29 8	$ 19 2
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 190 7	$ 182 0	$ 183 6
Net Cash Paid (Received) for Income Taxes	63 0	(13 0)	31 2
Noncash Acquisitions Under Finance Leases	8 8	5 5	3 5
Construction Expenditures Included in Current Liabilities as of December 31,	149 7	134 4	126 3

See Notes to Financial Statements of Registrants beginning on page 156

INDIANA MICHIGAN POWER COMPANY
AND SUBSIDIARIES

INDIANA MICHIGAN POWER COMPANY AND SUBSIDIARIES
MANAGEMENT'S NARRATIVE DISCUSSION AND ANALYSIS OF RESULTS OF OPERATIONS

COMPANY OVERVIEW

As a public utility, I&M engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 599,000 retail customers in its service territory in northern and eastern Indiana and southwestern Michigan. I&M consolidates Blackhawk Coal Company and Price River Coal Company, its wholly-owned subsidiaries. I&M also consolidates DCC Fuel. I&M sells power at wholesale to municipalities and electric cooperatives. I&M's River Transportation Division provides barging services to affiliates and nonaffiliated companies. The revenues from barging represent the majority of other revenues. I&M shares off-system sales margins with its customers.

Under the FERC approved PCA, APCo, I&M, KPCo and WPCo are individually responsible for planning their respective capacity obligations. The PCA allows, but does not obligate, APCo, I&M, KPCo and WPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

AEPSC conducts power, capacity, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M, KPCo and WPCo. Power and natural gas risk management activities are allocated based on the member companies' respective equity positions. Risk management activities primarily include power and natural gas physical transactions, financially-settled swaps and exchange-traded futures. AEPSC settles the majority of the physical forward contracts by entering into offsetting contracts. I&M shares in the revenues and expenses associated with these risk management activities with the member companies.

AEGCo holds a 50% interest in each of the Rockport Plant units and is entitled to 50% of the capacity and associated energy from each unit. Under unit power agreements approved by the FERC, I&M and KPCo purchase approximately 920 MWs and 390 MWs, respectively, of the output from AEGCo's 50% share of the Rockport Plant.

Under the SIA, AEPSC allocates physical and financial revenues and expenses from transactions with neighboring utilities, power marketers and other power and natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM generally accruing to the benefit of APCo, I&M, KPCo and WPCo and trading and marketing activities originating in SPP generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among APCo, I&M, KPCo, PSO, SWEPCo and WPCo based upon the common shareholder's equity of these companies.

To minimize the credit requirements and operating constraints when operating within PJM, participating AEP companies, including I&M, agreed to a netting of certain payment obligations incurred by the participating AEP companies against certain balances due to such AEP companies and to hold PJM harmless from actions that any one or more AEP companies may take with respect to PJM.

I&M is jointly and severally liable for activity conducted by AEPSC on behalf of APCo, I&M, KPCo and WPCo related to power purchase and sale activity.

RESULTS OF OPERATIONS

KWh Sales/Degree Days

Summary of KWh Energy Sales

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in millions of KWhs)		
Retail:			
Residential	5,409	5,731	5,311
Commercial	4,685	4,851	4,785
Industrial	7,589	7,836	7,781
Miscellaneous	69	71	70
Total Retail (a)	17,752	18,489	17,947
Wholesale	8,268	10,873	11,202
Total KWhs	26,020	29,362	29,149

(a) 2018 and 2017 KWhs have been revised to reflect the reclassification of certain customer accounts between Retail classes. This reclassification did not impact previously reported Total Retail KWhs. Management concluded that these prior period disclosure only errors were immaterial individually and in the aggregate.

Heating degree days and cooling degree days are metrics commonly used in the utility industry as a measure of the impact of weather on revenues.

Summary of Heating and Cooling Degree Days

	Years Ended December 31,		
	2019	**2018**	**2017**
	(in degree days)		
Actual – Heating (a)	3,782	3,886	3,213
Normal – Heating (b)	3,740	3,747	3,758
Actual – Cooling (c)	940	1,132	792
Normal – Cooling (b)	849	849	846

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Cooling degree days are calculated on a 65 degree temperature base.

2019 Compared to 2018

Reconciliation of Year Ended December 31, 2018 to Year Ended December 31, 2019
Net Income
(in millions)

Year Ended December 31, 2018	$	261.3
Changes in Gross Margin:		
Retail Margins		102.9
Margins from Off-system Sales		(10.3)
Transmission Revenues		(13.7)
Other Revenues		(2.7)
Total Change in Gross Margin		76.2
Changes in Expenses and Other:		
Other Operation and Maintenance		(48.9)
Depreciation and Amortization		(57.5)
Taxes Other Than Income Taxes		(6.2)
Other Income		(1.0)
Non-Service Cost Components of Net Periodic Benefit Cost		(0.4)
Interest Expense		6.2
Total Change in Expenses and Other		(107.8)
Income Tax Expense (Benefit)		39.7
Year Ended December 31, 2019	$	269.4

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $103 million primarily due to the following:
  - A $112 million increase from rate proceedings, inclusive of a $24 million decrease due to the impact of Tax Reform. This increase was partially offset in other expense items below.
  - A $23 million increase related to rider revenues, primarily due to the timing of the Indiana PJM/OSS rider recovery. This increase was partially offset in other expense items below.
  - A $6 million decrease in fuel-related expenses due to timing of recovery for fuel and other variable production costs related to wholesale contracts.

  These increases were partially offset by:
  - A $28 million decrease in weather-normalized margins.
  - A $23 million decrease in weather-related usage primarily due to a 17% decrease in cooling degree days and a 3% decrease in heating degree days.
- **Margins from Off-system Sales** decreased $10 million primarily due to mid-year 2018 changes in the Indiana OSS sharing mechanism.
- **Transmission Revenues** decreased $14 million primarily due to the 2018 PJM Transmission formula rate true-up.
- **Other Revenues** decreased $3 million primarily due to a decrease in barging revenues by River Transportation Division. This decrease was partially offset in Other Operation and Maintenance expenses below.